ALASKA STATE LEGISLATURE

SPECIAL SESSION

THE ALASKA GAS PIPELINE

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Reported by: Sandra M. Mierop, CRR, CCP

PROCEEDINGS

COMMISSIONER CORBUS: Could we get everybody to please take their seats so we could get going?

Well, good morning.

Welcome to the second day of presentations on the stranded gas contract and the fiscal interest findings.

Today we have four presentations, and your presenters will be myself, Bill Corbus, and Dr. Pedro Van Meurs.

Let's, again, review the rules of engagement. We're going to start these programs at the time called for on the program. We ask you to turn off your cell phones. We will take breaks between presentations, and if you have questions, please write them on the 3-by-5 cards that you should have at your table.

Please limit only one question to one card so that we can shuffle them around and hand out assignments.

We owe you an answer to a couple questions which came up yesterday, and we will answer those at the end of the program. We will answer programs at the end of the program, and we will not accept questions from the floor as we are going through the presentations.

I'm the first one on the program this morning, and my topic is a prepay overview of the preliminary findings and determination of the Commissioner.

This is in Section 9 of the fiscal interest finding -- I guess, probably, with the exception of the project description, is the shortest section of the finding.

The purpose of this presentation is to demonstrate that the contract meets the purpose of the Stranded Gas Development Act, as discussed in Section 9 of the preliminary findings and determinations.

On May 9th -- excuse me, on Day 9, which is May 20th, after your understanding of the contract and background, economic and fiscal data will be much better understood. We will -- Dr. Van Meurs and I will review the findings and determination again with you, only much more rigorously. We will talk numbers. We will try hard to prove our case to you.

The preliminary findings are required in Section 400(a)(1) of the Act, which says that the Commissioner shall make preliminary findings and make a determination whether the contract is in the long-term fiscal interest of the State and furthers the purposes of the Stranded -- Stranded Gas Development Act. The purposes are set out in Section 010. But the long-term description of what the long-term fiscal interests of the State of -- is not defined, described, or discussed. Therefore, it's up to the Commissioner, his call, as to what is in the long-term fiscal interest of the State.

The purposes of the Act, as I said before, is defined in Section 010, and we must be -- we intend to make the case that it does -- that this contract does satisfy the purposes of the Act.

Does the contract encourage new investment to develop the state's stranded gas resources by authorizing fiscal terms related to that new investment?

Does the contract allow fiscal terms applicable to a qualified sponsor group to be tailored to the particular economic conditions of the project and to establish those fiscal terms in advance with as much certainty as the

Alaska Constitution allows?

And, 3, does the contract maximize the benefits to the people of the state derived from the development of the state's stranded gas resources?

Now, this presentation and the findings -- the preliminary findings assume that the recommended changes to the Stranded Gas Development Act, which we are asking you to make, are in place.

So, what is the long-term fiscal interest of the state?

Here's my call: Does the contract generate additional revenue?

Is the State's share of project revenues fair?

Is fiscal certainty a necessary inducement for the project to go forward?

Is the period of fiscal stability reasonable?

Does the contract have a neutral effect on State revenue? What we're talking about is under the old system, the 2005 -- what we call the 2005 fiscal system, is this a -- are revenues comparable to revenues under that system?

And, finally, the state and local impacts, would it be fair to the state and local -- or to local communities?

Let's turn to each of these items and discuss them.

Generation of additional revenue. Oil and gas royalties and tax revenues make up about 75 percent of the state's forecasted general purpose revenue needed to finance state government. Based on forecasted revenue for the state, after fiscal year 2009, the State's revenues will not be enough to meet the anticipated shortfall, even with substantial new revenues from the Petroleum Profits Tax, if enacted. Therefore, the State must establish additional sources of revenue.

It is determined that the revenues would -- that would accrue to the State and local government would be substantial. Royalties and taxes on gas that is no longer stranded would be an additional source of revenue that will materially improve the State's long-term fiscal interests. The return on the State's equity investment in the project will also help to provide a modest but stable source of revenue.

The State's share of project revenue is fair. It is determined that the State's share of project revenues is competitive with other taxing jurisdictions which are faced with exporting gas over long distances to the Lower 48 market. The contract provides the State with a fair share of revenues of the project.

Fiscal certainty. This stability is the most important feature of the contract that achieves the purposes of the Stranded Gas Development Act. The fiscal certainty offered by the contract serves as a counterbalance for the possible economic, financial, resource, political, and regulatory risks that must be considered in the investment decision.

Lack of fiscal certainty or stability would expose investors to: Significant erosion of value under high prices, the point where the project becomes unattractive, taking into consideration capital invested in the past and very significant exposure to low market prices for gas and cost overrun conditions. For a very large project of this nature, such exposure is commercially not acceptable. It is determined that it is not adverse to the long-term fiscal interests of the State to grant fiscal certainty.

Making sure that the pipeline is full for -- for the contract term will increase the probability that investments will be made in the project at the project sanction date. The contract will also provide explorers the fiscal certainty required to invest in exploration for the gas that is necessary to keep the pipeline full over the period of fiscal certainty.

The main beneficiaries of increased production and transportation of gas are the State and affected communities, which will receive significantly more revenues proportionately with increased volumes and values. It is in the State's interest to take all steps required to increase the volumes to be produced and -- and transported through the main line.

Period of fiscal certainty. The period of fiscal certainty is reasonable. The term of the contract would cover the 10-year period of project development, permitting, engineering, planning, procurement, and construction, plus an additional 35-year period after the commencement of operations. Within this term, different periods of stability are provided for taxes on oil and gas.

Fiscal stability for gas applies for the duration of the contract, while fiscal stability for oil is limited to 30 years from the effective date of the contract. The period is reasonable to cover the depreciation period expected to be set for the gas pipeline. The depreciation period is important for rate purposes -- setting purposes, and will be set after considering the reserves available for transportation through the gas line.

It is determined the 35-year period of fiscal certainty for gas granted after the commencement of commercial operations is reasonable and necessary to provide an effective inducement to build the project. It is also determined that a period of fiscal certainty is necessary to cover the period to explore for, locate, and develop additional reserves to fill the gas line to capacity for the duration of the contract.

The 30-year period for oil is

designed to provide a stable regime up until approximately the time when decisions related to the use of potentially available capacity on the main line have to be made in order to keep the main line full for the contract term.

New exploration efforts will typically be for oil, as well as gas. A detailed analysis of international exploration and production contracts indicates that a 30-year fiscal certainty period is a relatively short period for a high cost and high-risk area, such as the Alaska North Slope.

Neutral effect on State revenue. The effect of the contract on State revenue has been evaluated against the 2005 fiscal terms. Gas revenues are compared on an undiscounted basis. Gas revenues are slightly less on a net present value basis under the proposed contract. The revenue results are very similar because the contract retains the same royalty. The protection -- the production tax payment of 7.25 percent is approximately the same as the existing production tax when adjusted by the ELF, while the State corporate income tax also remains unchanged.

State and local impacts. As described in the findings report, it is estimated that the 125 million -- that's in 2003 dollars -- in additional expenditures would be incurred by the State, municipal, and village governments in support of education, health, public safety, and other services during the project preconstruction and construction period.

Based on the data of the Department of Transportation and Public Facilities, the cost of transportation projects prior to construction may be $400 million. The cost of rehabilitation after construction may be $800 million.

These projected economic impacts are partially offset by $125 million that the contract requires be paid in impact payments during the preconstruction and construction period. It is likely that Federal matching money will also be available to offset some of the costs and the sponsors may contribute to some costs for the projects directly benefiting from facilities caused by construction activity.

In the short term, development of the project may place significant capital and operating costs on state and municipal governments for the extension of services to residents and other infrastructure needs. It is determined that this is in the short-term effect attributed to the project, which does not significantly diminish the long-term beneficial fiscal effect of the contract.

Summing it up, a general determination, as far as is it in the long-term fiscal interest of the State, based on these foregoing factors, which I have reviewed with you, the terms -- the proposed terms of the contract are termed -- are determined to be in the long-term fiscal interest of the State.

Now, let's turn to the second way of coming at this, which is: Does the contract meet the purposes of the Stranded Gas Development Act? Here our job is easier because we are given some direction in the statute as to how to go about this.

Does it encourage new investment?

Does the contract -- is it tailored to the specific economic conditions in as much fiscal terms in advance as the Constitution allows? And we're going to break that into two questions.

Tailoring, is the contract tailored to the specific economic conditions?

And 2, the issue of constitutional fiscal certainty.

And then we're going to take a look at the maximum benefits, does -- the question as to whether the contract maximizes the benefits to Alaskans, employment and training revenues and gas for Alaska.

Encourage new investment. The proposed contract will encourage investment in the single largest gas development project in the world, and will result in the development of the stranded gas. Furthermore, the contract encourages exploration by providing a means for expanding capacity of the pipeline system when future discoveries are made and reserves identified. These expansions will ensure that the new gas discoveries get to market.

The fiscal terms of the contract are customized to the conditions of the project because the terms were negotiated as arm's lengths with the commercial interests of the sponsor group balanced against the public interest to be protected by the state.

I think I got a slide out of order here. No, I guess not.

The question of whether the fiscal terms of the contract were established with as much certainty as the Alaska Constitution allows is a question of law. In that regard, advice was received from the Attorney General that the fiscal terms of the contract do not violate the Constitution.

Does the contract maximize the benefits to Alaska and Alaskans?

Let's look at employment and training. The contract furthers the goal of Alaska residents by providing that project. Employment, it allows for employment of state residents and contracting with business in the state to work on a construction and operation of the project to the extent these residents and businesses are available, competitively priced, and qualified.

It will provide for advertising for available positions in newspapers and other publications throughout the state. Use will be made of job service organizations located throughout the state in order to notify state residents of work opportunities available on the project; work within the state to plan training and opportunities for state residents and to incorporate substantially similar agreements with other contractors.

The contract requires the project to spend or cause the spending of a combined total of $5 million in paying for workforce training programs and activities in the state, in addition to another $34 million already available for other -- from other sources.

Maximize benefits. Revenues. As stated in Sections 1, 4, and 5 of the fiscal interest finding, the revenues from the project will be very significant to the State and some municipalities. Revenue share will be competitive with other jurisdictions and will be close to the 2005 fiscal system.

Increased revenues will help bridge the projected state fiscal gap resulting from lower oil production and ever-increasing costs of operating government. A portion of royalty revenues will be deposited in the Permanent Fund principal, resulting in increased realized earnings.

The contract also provides for access for natural gas in -- for in-state markets. Prior to the open season, in-state needs will be identified by a study completed or adopted by the project. In consultation with the State, four off-take points in Alaska will be provided by the main line entity to accommodate in-state gas consumption.

Summing it up as to whether this contract satisfies the purpose of the Stranded Gas Development Act. Based on the foregoing, it is determined that the contract will maximize the benefit to the people of the state by a development of the state's stranded gas resources in a timely and orderly manner.

So, my conclusions in the preliminary findings are, first, the contract is in the long-term fiscal interest of the State. And, second, that the contract furthers the purpose of the Stranded Gas Development Act. These findings will be addressed again more vigorously, supporting data, on May 20th, Day 9 of our presentations.

Thank you. And let's take ten

minutes.

[Break]

COMMISSIONER CORBUS: I think we're ready to get started now.

The next item on the agenda is a presentation by Dr. Van Meurs and myself on the fiscal certainty on oil and gas -- what it means and why it matters.

Dr. Van Meurs.

DR. VAN MEURS: It is a great pleasure, again, today to start looking at all of the economic details of -- of the broad concepts that -- that I presented yesterday.

In fact, I haven't even counted the number of slides that I will be presented today, but it is something like 120, full of graphs and figures. And so, definitely, by the end of the day, you'll have seen more economics than you want to see for a long time. In fact, this almost -- I think you will qualify as an economist at the end of the day. Normally, around the world I give courses on this, and I really think I should give you a diploma at the end of the day for -- for just listening.

So this is -- what I like to do

first is discuss -- before we go into the details of fiscal certainty and profitability, what I'd really like to do first is discuss some of the basic economic assumptions, some of the model assumptions because a lot of the discussion in the coming weeks will center, of course, on a lot of the details.

And, consequently, I will start with the most boring part of the economics, which is the assumption about the model. Actually, the State has worked with four different models. There is the DOR model that -- that was developed -- or is still developed by Roger Marks. Then there is the DNR model, which is developed by Greg Bidwell and William Nebesky. Then there is the PVM model, that is me, Pedro Van Meurs model and I developed that primarily for the purpose of the negotiations. And then there is the InformationInsights Regional Model to look more at economic impacts.

Now, why was it that we had all these models? All these models serve different purposes. But interestingly, the overall conclusions that come out of all of these models, although all the detailed assumptions are often different between them, all the broad conclusions that come out are all confirmed among the models. So, we know that if -- if we conclude something, it is not because we used this model or another. The three models all lead to the same conclusions, and that reinforced our views that, you know, we -- we are looking at this in -- in the right way. And -- and the kind of factors that are different among the models really are not factors that would change the basic conclusions.

Let me speak a little bit about the PVM model. That is the model that I will -- that I used all day -- or that I used all the last -- rather, the last two years during the negotiations, and that is the basis for all of the work that I will be presenting today.

I actually assume an eight-year period prior to first gas, four years feasibility and regulatory work, and four years construction rather than the more traditional ten-year period. The reason that I used a somewhat faster construction period is that that, of course, improves the net present value, improves the rate of return, and I didn't want to present figures that, say, were too low. So I erred on the side of -- of a higher rate of return and a higher net present value. Because, of course, the longer you make that construction period, the less the net present value of this project becomes and the less rate of return of the project becomes.

So I used a relatively aggressive construction schedule. Then I used 30 years of production and transportation.

The reason that I used 30 years, again, is to be conservative. The problem is, as was well-explained by the Commissioner Mike Menge of DNR, we really only today have gas that is sufficient for 30 years. We haven't found the gas yet that is going to fill this line. And, consequently, it is very difficult to make economic assumptions about what the costs are of the gas that we haven't found yet. And, consequently, I wanted, therefore, to make my model somewhat more conservative and stick with the resources that we know. Even at 30 years, we have -- we need yet to find gas in order to fill the pipeline.

On top of that, I -- my model is a gas-only model. The reason is that the stranded gas contract is really a gas-focused contract. Roger Marks in his model, as he so well presented to the Legislature in January when we discussed the PPT, his model really deals with the condensates and other, say, liquid effects of -- of the pipeline, which are very positive.

But I concentrated on the gas-only side of the model because that was the core of the negotiations. And the oil side has certain complications to it which are difficult to assess. For instance, what is precisely the oil loss that will occur in Prudhoe Bay if you start to produce the gas? If you start to produce the gas, hundreds of millions of barrels of oil will actually be lost as a result of the -- of the declining pressure, because gas is no longer reinjected. These volumes lost are difficult to estimate. So, I didn't want to, quote, pollute my -- my model with assumptions that I really didn't have good verification for.

I use everything in 2006 dollars. My model is actually based on an aggregation of individual cashflow, so individual economic analysis. That means I look at the upstream, and I make a profitability analysis of that, and then

I look at the GTP and make a profitability of that, and then the main line, and the part in Canada, and if there is a Lower 48 line all the way to Chicago; I make separate economic cashflows for all these projects, and then I add them all together.

So I have an aggregation model. Roger Marks, for instance, has a -- has a unitary model.

As we discussed yesterday, one of the enormous risk factors of this project is: Can we sell all the gas in Alberta or do we need to make additional investment commitments to get the gas all the way to Chicago? And this depends on the take-away capacity in Alberta that -- that we already discussed yesterday.

The main purpose of the PVM model was to do profitability analysis on the position of the companies because this was a negotiating model. We needed to understand the profitability of our partners in the project to understand -- to look in their minds and to understand what they're worried about and -- and what they're maybe not worried about. And, of course, I set the model up in such a way that in conjunction with the profitability analysis we could do the government review analysis.

So, as you can see, my -- my model is somewhat different, has different assumptions than Roger used or DNR used. DNR has a model for the entire contract period, for instance. So, there are differences between the models. But, interestingly, as I said, the overall conclusions of all the models are -- are approximately the same.

Here are the capital cost expenditures that I used for the Alberta project and the Chicago project. I allocated 75 percent of Point Thomson to the gas, and, consequently, I assumed 1.5 billion, $1.6 billion capital expenditures. That, of course, is the same whether you have the Alberta project or the Chicago project. Then you find this round number of 4 -- 4 billion because, as I said, we don't even fill the line for 30 years. So, we have to make assumptions about capital expenditures that we need to really keep the line full for that period. And those capital expenditures actually are not known. We don't know precisely what it will cost to fill the line with the additional gas resources.

So, what I did is I assumed that we would probably need to find something like a two and a half times Point Thomson and that consequently, we probably would be in for about 4 billion additional expenditures just to keep the line full.

Then the Point Thomson feeder line to the GTB, I assume 265; the GTB itself, 2.5; the Alaska main line, 5.3 billion. And then you find the difference between the Alberta project and the Chicago project. Of course, the Alberta project just goes to the B.C. Alberta border, and I assumed another 5.3. If you have the Chicago project, then you have a pipeline that goes all the way from the Yukon border to the Saskatchewan border into the Lower 48, and that estimate was supposed to be 10.6, is -- I determined as 10.6. All these figures, by the way, are based on the simple assumption of $20 billion in 2003 dollars. I didn't want to use the data of the data room because I wanted to make a model that was nonconfidential. So, if anyone is interested in checking my figures, they can do so. And consequently, anyone -- interested party can contact the government, and -- and my model is nonconfidential, and it is available.

Then, for the Lower 48 pipelines, there is 2.7 billion.

Now, then you see Alberta hub, because if you get to the B.C./Alberta border, you still have to get into Alberta in order to get to the hub. Actually, I assumed that there was no pipeline connection necessary, because there is enough capacity in Alberta. And, consequently, I assume simply the 18 cents Alberta hub entry fee, and that will then connect you to the pipeline system in Alberta.

So, here you see it. If you -- if you include the 4 billion necessary for new development, we are talking, in total, 19 billion for the Alberta project and 27 billion for the Chicago project.

As I mentioned, this is based on 20 billion in 2003 dollars. As I mentioned yesterday, there is actually quite considerable evidence that these costs have already escalated significantly since the time these estimates were made. Nevertheless, for the purposes of the evaluation, I wanted to be conservative, and, consequently, I stuck with the original figures.

A lot of assumptions are made about operating costs. The conditioning plant, GTP, better word, was suppose -- I assume 2.5 percent off. It's called Capex there. That stands for capital expenditures. And then the pipeline, 1.5 percent of the capital expenditures per year, I assumed the upstream cost to be 45 million per year.

Then if you sell the gas in Alberta, rather than in Chicago, of course, you get a lower price. You get a lower price for the gas, because the value of the gas in Alberta is less than in Chicago, because people still have to move the gas to Chicago. And, consequently, I assume an 82 cents differential. But I also assumed that the differential would decline in 2026, and the reason is that that is the period where a lot of the depreciation runs out on the Canadian lines and where it is likely that pipeline tariffs will be lowered. So, consequently, by 2006 (sic), we may actually see lower pipeline tariffs out of the Alberta hub, depending, of course, very much on the takeaway capacity and the volumes that are being transported.

Then, a general Btu, I assumed that there were 1.08 million Btu per thousand cubic feet.

If I did analysis in what economists call nominal dollars, inflated dollars, the dollars as you actually receive them, say, from year to year in the future, I used 2 percent. I used the cost of debt for the pipeline of 5.5 percent; equity, 14 percent rate of return; in Canada, 12, because the national energy board is typically a little bit more stingy on -- on equity. And I used the 80/20 debt equity for most of my runs and for the determination of the pipeline tariffs. Of course, with the significant support from the Federal Government, the 80/20 debt/equity ratio is -- is very well supported.

So, here you see all kinds of detailed assumptions. These are the assumptions that I made about gas, how much gas is there available in the various field. I use stylized decline curves, not actuals, in order not to -- to, say, infringe on confidential data.

I used -- I assumed that there was

22 tcf of gas coming from Prudhoe Bay, 10.9 from Point Thomson. The reserves are actually announced as 8 tcf, but DNR is confident that in the northern parts of the field and other parts there may be some more gas there.

Then for the yet-to-find, it is difficult to say. And I assumed that half would be found in leases where the State actually can charge a royalty, and the other half would be in NPRA where, really, the royalties are Federal, but the production tax is State.

So, just for the 30 years, you need 44 tcf of gas, of which already 35 is found. So, even for a 30-year cashflow, as I did, you need to find another 9 tcf. You need to find another Point Thomson equivalent. So this is -- this is very significant.

If you would move this out to the 35 years that Roger uses and that is the length of the contract, you need to -- the total gas that you need is 51 tcf. So now you need another 7 tcf on top of it. So then you would need 16 tcf. And that is such an important issue if we look at fiscal stability, because this line is by no means full. And in my economics, even on the 30-year cashflow, I just assume it is full.

Now, that's a big assumption. And, consequently, that is actually an unusual way of comparing projects. Normally, if you compare projects around the world, you don't include gas that you haven't found yet. So, consequently, if I compare the Alaska gas project with other projects in the world, I'm actually throwing in 9 tcf of gas that we don't -- haven't found yet. So, that is a pretty liberal assumption.

As the Commissioner of DNR explained so well, we are very optimistic that we will find it. But we don't have it yet. So, if you go to the banks, that doesn't sound very good. So, that is a very important set of assumptions.

In my model, I can run before financing or after financing. International oil companies usually run all their economics on a before-financing basis, and that is what I did for all my slides that I've presented. And -- and the reason is very simple. If you are a large international corporation, you really don't finance against a particular project. You don't have to do project financing.

Say, if Exxon Mobil goes to the financial community and wants to borrow, they just borrow against the corporate balance sheet. Everybody believes that Exxon is good for it. And they will not look at the actual project. They will not look at a particular project and say, You can borrow so much. No. Exxon or BP or ConocoPhillips, they just borrow against the whole company. They don't borrow against a particular project.

And if they look at projects around the world, they like to get the best portfolio before financing. And then the financing is done and had where it is against the corporation. As long as your projects are good before financing, then you have a healthy company. That's how they make their decisions.

So, that is what I largely simulated in the model. Of course, we can do it after financing as well in order to study the impact, say, on Alaska financing. Nevertheless, all my tariffs are calculated assuming that there would be financing in order to arrive at the amount of the tariff.

In order to do real economics, I

made a simplification in my model. I just assumed that there would be no inflation or escalation. That is actually a simplified way of doing real economics. Normally, you escalate and then you discount for inflation. But I -- I wanted to not kind of pollute my assumptions again by assumptions about escalation rates. And actually, the other models of the State used the same.

A very important aspect and a very important question that many people ask is: If the State starts to market its own gas, how much is that going to cost? And so, consequently, in order to compare the proposed contract with the status quo, I assumed a very high cost of gas marketing. So I assumed that the gas marketing would be very costly. And, in fact, I assumed 5.5 cents per million Btu. If you go to the average gas marketer in the world, he will tell you that on long-term, large-volume contracts, you can probably bring this down to 1 cent. But I used a very high assumption in particular because I wanted to absolutely make sure that if we looked at the proposed contract, that we did not underestimate the marketing cost on the part of the State.

Now, this is a large assumption. This is assuming that it is going to cost the State almost half a billion dollars over the next 30 years to market its gas, so that has a huge impact on the total economics of the model, and I think that is an extremely high assumption. But I wanted to do that because I want to make absolutely sure that we didn't underestimate these marketing costs. But most experts believe that these costs could be significantly less than I estimated.

Then there is, of course, a lot of discussion comparing with the status quo. And, really, of course, everyone likes to know, Did we give something up? What did we give up? What is the relationship to the status quo? And the first point I want to make about that is that, as you all probably have already seen yesterday, but I will demonstrate in a lot more detail today, with the status quo, you do not necessarily have a gasline. So you can look at the status quo and say, what -- what is this?

The probability that this gasline will be built under status quo terms is extremely low. So, consequently, this is not necessarily from an economic point of view a rational scenario to compare with. In fact, if you look at what we call, typically, the status quo on the North Slope, what -- what is it? It is really nothing else than the oil terms applied to gas. That's basically what it is.

Now, if -- as Daniel Johnson explained so well to the Legislature, if you look around the world and if you look at nations that export large-distance gas, what you will see is that the government take for gas is about 10 percentage points less than for oil. Or in other words, most gas exporters have fiscal regimes for gas that are considerably more lenient than for oil.

And, in fact, what this Legislature is about to do, I hope, over the coming period, is that we are actually following the international practice. By adopting a stranded gas contract that creates about the same revenues as the status quo, we are actually leaving the government take for gas where it is. And as we reviewed in the Legislature, for oil we are going to increase it. So, consequently, rather than decreasing the government take for gas, if you look at the whole package, we leave the government take for gas where it is, and we are increasing the government take for oil. That's really the whole concept of the PPT legislation. That is why we would collect so much more money with that PPT under average oil price forecast.

So, consequently, that -- that is really, by the fiscal contract and the PPT law together, we actually have a package that is really very similar to what many other nations in the world do.

Nevertheless, I do believe that it is useful for the Legislature to compare with the status quo. And it is not because it is an economic rational comparison, but it gives you a good order of magnitude feel of -- of what this deal means. You know the terms of the status quo. You're intimately familiar with it. So, consequently, if you compare with the status quo, it is kind of like a benchmark for you. It is a benchmark to see how you feel about this -- this contract. And that is why we will be comparing with these 2005 fiscal terms.

Although I happily talk about the

status quo as if this is something that we know, actually, the status quo would be subject to a lot of debate. We actually don't know what the status quo is. That's a very interesting point that can be easily demonstrated.

I mentioned we need to find 9 tcf of gas yet to find. What would be the production tax? What would be the ELF on this yet-to-find gas? That is pure speculation. So, consequently, you can fill in any number you want, depending on what you believe and where you believe these gas reserves are going to come from.

So, the status quo is not kind of a fixed number that we know precisely. It depends on estimates. It depends on what we think. And, consequently, we have to make all kinds of assumptions, if we want to compare with the status quo, what the status quo actually is.

So, actually, between the Department of Natural Resources and DOR, in September last year, lengthy discussions were held, and we landed on what we jointly would consider between the two departments what the status quo actually is. But that is just an assumption for working -- working hypothesis.

Firstly, we assume the royalties in Prudhoe Bay for gas, of course, to be 12.5 percent. In Point Thomson, we assume 14.5 percent. As you may well know, that's currently under negotiation, and it may actually be somewhat less. It may be 14.2. It may also be somewhat more, maybe 14.8. That's exactly what DNR is doing today. They are sitting together with the oil companies to find out precisely what is the average royalty.

Outside Prudhoe Bay and Point Thomson, there are some other gas resources that could come on stream, and, typically, some of that have higher royalties. So, consequently, I assume 13 percent for those. I assume we would receive in cash 6.25 percent on federal leases.

There is a field cost allowance of 22.4 cents per million -- sorry, per thousand cubic feet in Prudhoe Bay only. We -- there is no field cost allowance in other fields.

We assumed that there would be only processing cost in -- in Prudhoe Bay, and, consequently, not in other fields. That is uncertain, actually. There is a lot of debate about it. The oil industry doesn't necessarily agree with this assumption. They feel that under certain leases there would be processing costs in -- in other fields.

Point Thomson is the most difficult one to -- to really get a grip on as far as the net profit share is concerned. What I did is I simplified the net profit share on Point Thomson, and as you will see from the deal, actually, Point Thomson is really the same under the status quo and under the -- under the stranded gas contract. So, the -- the net profit share on Point Thomson is simply going to be paid. It is whatever it is under the contract. No change was made. And the reason was precisely because it was so difficult to calculate. So it was difficult to negotiate a different figure for it or a -- or a stylized figure for it.

So I assumed that on average Point Thomson would deliver 2.2 percent, equal to an -- to an -- say, a share of 2.2 percent of the total field production, but after the costs are recovered. And in my model I then have a formula to see when the costs are recovered, and under low prices, the costs may not be recovered at all, so you won't get anything and under very high prices, the costs may be recovered in a few years. So, consequently, Point Thomson is in significant variable.

A very important issue is: If we switch from our current royalty system to committing to take the royalties in kind, we give up potential value. Because right now under the lease agreements, the State has the right to pick the higher of the values in the market, and not for whatever it can sell. Plus, the State has the flexibility to switch between royalty in kind and royalty in value. And that's worth something. That is worth to have that flexibility. And it is worth to have that higher of the value.

So, Lukins, our advisors on gas marketing in North America, did an in-depth analysis of what that would be worth, and we came to the conclusion that that is about equal to 2 percent of the market value of the gas. So I added in the model 2 percent to the market value of the gas for the status quo, because that's value that we would otherwise receive. And under the proposed contract, we would give that up.

So, if you compare the status quo with the proposed contract, I have already included 2 percent for this higher-off value and this RIK/RIV switching that the state is giving up.

Very important and very difficult assumptions needed to be made with respect to the production tax. The Department of Revenue has every year a petroleum engineer evaluating what the forecast for the production gas -- for the production tax in gas would be in Prudhoe Bay and in Point Thomson, and these estimates change all the time because it all depends on the amount of wells that's there. It depends on how you believe oil production will evolve because it all goes to the well count, even for gas that we have in per-well assumption in the ELF formula, so you have to know -- make assumptions about a number of wells. You have to make assumptions about oil production and so on. So, it is not that easy to actually estimate the future of the production tax, the future of the ELF.

However, what I did is I looked at the latest engineering estimate, and I stylized it a little bit so that it is actually a good, conservative estimate, and that means that for Prudhoe Bay, I assumed that the production tax starts at a rate of 7 percent; then declines to 5.48 percent; and at the end of the forecast period, Prudhoe Bay is almost exhausted, and the production tax would be very low, .48 percent.

Point Thomson is a much better field, much higher well productivities. It is anticipated that the production tax will practically be 10 percent and that that will last for a good while, that that -- that the field production is quite high. So I assumed that it would go down to only 9 percent. This is all based on these engineering studies that were done. And then maybe to 8 percent at the end of the forecast period.

For the yet-to-find, after lengthy discussion among the various officials in the Department, we just decided to fix it at 7 percent. Now, this figure could be anything. So, here you see the difficulty of what the status quo is. It could be much less. In fact, the oil industry believes that it will be much less. But there are other experts, which I also highly regard, who believe that it could be somewhat more. So, consequently, in the end, we thought that the 7 percent was probably a good number.

We assume also processing costs of only 2 cents. The processing costs are actually more now, but it is believed that under the current regulations that -- it was assumed, under the status quo that we could make a good case for lowering these processing costs in view of the much higher volumes that would be sold.

So, that is as far as -- as the production taxes are concerned.

This is prior to the upstream property tax in my model. Currently, the upstream property tax for oil is on average about 50 cents per barrel. It is different field by field. So I -- but I assumed, I simplified it. It comes out at roughly 50 cents per barrel, so I forecasted that with full inflation. And then an estimate was made for the possible production tax on gas under the status quo, and that was believed to be about zero point -- sorry, 2 cents per mcf.

The midstream property tax was based on how the Department of Revenue always does it. That is 2 percent per year, of course, on the replacement cost, less the depreciation.

Corporate income tax, we just assumed that 9.4 percent rate. However, as you well know, there is all kinds of allocation formulas, and in reality, on the upstream, the State doesn't get its full 9.4 percent.

It is very difficult to estimate what the exact percentage will be. Here is another big problem with defining the status quo, because the corporate income tax is based on worldwide income, and it is nearly impossible to estimate the worldwide income, let alone the share that Alaska will get from it.

But we simplified it, and we just said, okay, the experience of the Department is that the actual taxes collected over the last ten years seem to be approximately half of what you would calculate, and that is what we used in the model.

Now, as we will explain, there will be no change as -- as the Commissioner of Revenue, Bill Corbus, already explained to you. There's not going to be a change in the corporate income tax, so it doesn't really matter what you assume. It will go in either the status quo or in the proposed contract.

PPT terms, a very important issue. Interestingly, as I explained also to a number of legislators when -- when discussion took place on the -- on our famous gross revenue exclusion under the -- under the PPT, my assumption in the model is that all of the deductions and all of the credits are taken against the condensates. So it doesn't affect a gas-only model. So, in my economics, I assume that there is -- that the condensates have sufficient value. A memo to that respect was distributed among some of the legislators, I understand, that condensates have sufficient value to absorb the PPT cost for oil, and, consequently, I'm not assuming any deductions on the gas.

The contract will include a new PPT feature, or that is depending, of course, on where the PPT legislation goes in -- in the first place. But it is assumed in my economics that there will be an additional PPT feature in the contract, or an equivalent of this somehow or similar feature, that looks like 35 percent tax credit on the feeder lines and the GTP. That was included in the -- in the model. That was discussed a number of weeks ago or months ago already. And, consequently, that was included in the model.

At this point in time, it is, of course an open issue where -- where we go on this topic. But for modeling purposes, this is actually quite a critical feature, as you will see from the analysis.

So, that is, basically, the summary of the model. What I tried to do in all my work, as you can see, is portray the status quo as favorably as possible and the proposed contract as unfavorably as possible. Because I didn't want to get in a situation where people would say, yeah, you are just proposing this contract, and you're comparing it, and now it looks better or it looks the same, but that's just because of your assumptions.

So, consequently, what I tried to do is be conservative on the proposed contract, and be somewhat optimistic on the status quo. Now, people may disagree with me on the individual assumption, but that was at least my intention.

So that is the discussion of the model. As you can see, it is a gas-only model. The basic underlying assumption was, as -- as was also explained in -- say, in January to the Legislature, that the deductions for PPT that are taking place under the PPT bill would not affect the gas economics because all these deductions can simply be taken against the condensates and the oil.

So, that is a whole set of assumptions. It is always difficult to make the discussion of a model exciting. So, I'm sorry for this ream of basic information, but, obviously, this is -- it is very important to go over the basic assumptions, because everything I will discuss today depends on it.

And that is the end of this presentation. What we will do now is put on the next presentation right away so that we can...

Now, we have already discussed -- we're already discussing the proposed contract with you as if you already know what's in it. We haven't told anybody yet officially what's in it. So, that is what the Commissioner of Revenue will now deal with.

COMMISSIONER CORBUS: Hello, again.

Dr. Van Meurs was talking about his model, and he -- he touched on some of the assumptions, and he also touched on some of the terms that are -- fiscal terms that are used in -- in his model.

I am going to summarize for you the fiscal terms that were in -- that are in the contract. These terms were negotiated and agreed upon between the State and the producers.

First of all, the contract term. It provides for up to 10 years to construct the project and 35 years of production and operation, for a total not to exceed 45 years.

State equity participation. The State has the right to participate in 20 percent ownership of the gas treatment plant, the Alaska main line, the Canadian main line to Alberta, and an NGL plant, if located in Alaska.

The percentage ownership will be based on a through-put of the feeder lines and the pipeline to the Lower 48. That is the percentage of the State's through-put versus other people's through-put.

The State will take its gas -- its

royalty gas in kind. The percentage of the royalty gas is whatever the -- the leases in effect are at the time. As we say, royalties are what they are, is what was the jargon used in -- in the negotiations.

In other words, what is in the individual leases, that is the royalties that will be used for the purpose of this contract. Some leases -- most of the leases at Prudhoe Bay are 12.5 percent. There are other locations on the Slope where the royalties are as high as 20 percent. In any event, whatever is in the lease, those are the royalties that will be used for the purpose of the contract.

The percentage for Point Thomson is still being determined. That is not part of the contract. That is a -- a lease matter.

For new leases yet to be signed, there is no restriction on the level of royalties. The State can fix royalties higher than the 12.5 percent that we normally think of. New leases may be added to the contract with these higher royalties under certain conditions.

Tax gas. Production tax -- production tax is based on a flat rate of 7.25

percent. This percentage applies to gas after the royalties have been taken out or we say net of royalties.

Production tax before first gas through the pipeline is calculated on a value based on a formula in the contract, which is basically the -- whatever the statutory tax rate is on gas.

The State exercises a one-time option to convert the production tax in value to a 7 and a quarter percent tax in kind at the time we go to production -- or we go to first gas going through the pipeline. The State will pay an upstream cost allowance of 22.4 cents per mcf on all royalty and tax gas taken in kind.

This graph shows our estimated percent of total gas production that we expect to receive over the years. Note that when the project comes on line in the 2014/2015 era, it's just under 20 percent and falls off to around 17 percent at the end of the life of the contract.

Why is this? Because we are going to be having different leases at different royalty rates. This projection is based on a number of assumptions.

Upstream property taxes. On average, for oil, it's going to be 50 cents per barrel. It will vary from field to field. For new fields, it will be 50 cents per barrel escalated at 80 percent of the Consumer Price Index. For gas, it will be 2.1 cents per mcf escalated with 70 percent of the Consumer Price Index.

Midstream property taxes. When I say "midstream," that's the property taxes on the pipeline on the gas treatment plant -- 1 cent per MMBtu on the gas treatment plant and 2.4 cents per MMBtu on the main Alaska pipeline.

Note: For the upstream that the property tax is based on the volume of the gas, whereas the midstream is based on the heat content of the gas, MMBtu. Millions of British thermal units is the measure of heat content.

An impact fund of $125 million will be established and distributed to impacted communities during construction of the pipeline.

Corporate income taxes. There will be no changes in the corporate income tax from those in existence today. Today's corporate income tax will stay unchanged for the duration of the contract for the -- for the natural gas.

PPT credit. There will be a 35 percent credit on capital expenditures on the gas treatment plant and the lateral lines leading to the gas treatment plant.

Fiscal stability period. Fiscal stability period on gas for the -- will be for the duration of the contract, 45 years. Fiscal stability on oil will be 30 years from the effective date of the contract.

That sums up the fiscal terms that were agreed to in the negotiations with the producers.

And with that, let's take a ten-minute break. Thank you very much.

[Break]

COMMISSIONER CORBUS: First of all, we've had requests for copies of the PowerPoint presentations. They are being duplicated, and a copy of each of them will be placed on -- on your desk. We apologize for not having them done last night. Frankly, I guess we were in the same boat that you were. We were so tied up with the closing of the Legislature, that in some cases they were not completed until this morning.

So, with that, I'm going to turn it over -- back to Dr. Van Meurs, who's going to talk about the analysis of the deal, the producer profitability.

Dr. Van Meurs.

DR. VAN MEURS: During the remainder of the day, I will deal with -- with three main issues. One is the analysis of the deal from the producer point of view -- then -- or I like to state it differently, how we see the producer point of view and the -- then analysis on fiscal stability, the importance of fiscal stability, and then the analysis of the benefits to the state. So that will be the -- the sequence of -- of presentations.

So, first the analysis of producer profitability. Obviously, as we discussed already yesterday and early this morning, one of the objectives of the Stranded Gas Act, is to improve the competitiveness of the project. And, therefore, we have to look at the profitability of the project and see how this profitability can be precisely improved.

And that is what I will discuss, say, at great length, because it is important to understand -- for the understanding of why the deal is the way it is. It is very important to understand how the profitability of the project was modified in detail.

What I will do with you is systematically leave you seven different profitability indicators. And you may ask: Why do we need to look at as much as seven profitability indicators? Why not just look at the rate of return? Or why not just look at one?

Now, a petroleum economist is just like a doctor. If you go to the doctor and you say, "I feel sick," the doctor will not just take your temperature. The doctor will look at everything -- look in your eyes, look in your tongue, see whether you have a broken leg. Like, if you are not a healthy patient, then you have to look at all of the symptoms. And this pipeline is not a healthy patient. So, we have to look at all of the symptoms and give the nice amount and the precise amount of vitamins necessary to bring this patient to a good, healthy position.

That's really what petroleum economics is all about. How much vitamin E, and how much special, say, medicine, and a good back rub, and then by the end, we are -- we're probably healthy. And -- and that is how you treat the economics of a pipeline. You have to look at every little aspect of this profitability.

So, what I will do with you is go through all of these aspects of profitability and discuss the importance of them.

Firstly, the rate of return. We discussed it already yesterday. Most of you will -- will be familiar with the concept of the rate of return. It is an easy concept. The rate of return compares directly, really, with the interest that you would receive, say, on a -- on a bank loan. If you receive interest plus your money back, say, that is kind of like the rate of return on your loan. In other words, the rate of -- the higher the rate of return, it is like the more interest you get on 100 percent of your capital.

For instance, yesterday I mentioned this target of 13 percent rate of return, say, for $3.50. That is real and I used 2 percent escalation. So that means that that really compares with 15 percent interest on a loan. That's basically what it is. That is what the rate of return is all about.

As we discussed yesterday, the Achilles heel of this project is the low rate of return. And this is a graph that I already showed you yesterday. It is a repeat graph just to remind you of -- of this rate of return issue.

As we discussed yesterday, what is this graph representing? This graph is representing 60 large competing projects, and for each of the projects, we calculated the rate of return under a whole range of different oil prices. And that is what all these strings of beads are. On the left-hand side is the lowest oil price, $15 a barrel. On the right-hand side is the highest price, $60 a barrel.

And, obviously, as you can see on the bottom of this graph, the higher the price, the higher the rate of return.

If you go along the string of beads from the bottom to the top, the projects become less and less attractive. There's a lower and lower rate of return.

Now, we can actually take the line

most to the left and what you see there is this string of triangles. And if you get all the way to the top, you see actually a green square. Then you see this red dot and a blue dot. That represents, actually, the rate of return of the Alaska gas project.

So, you see that under very low prices, actually the rate of return is -- is essentially the lowest in the world under the status quo.

If you go to the contract, it is still in the lowest 15 percent of the projects in the world. Red means without the 35 percent GTP credit. Blue means with the 35 percent GTP credit. This GTP credit has a very important impact on the rate of return. So that is why it is proposed as a -- as a component of the project.

Now, what you also see is that if the project becomes -- sorry, if the prices go up, what you see is that actually the rate of return, of course, goes up, of all the projects and so does the rate of return of the Alaska project. But, as we discussed yesterday, the rate of return stays relatively unattractive if you compare it with all of the other projects in the world.

And, really, with this stranded gas contract, with this State participation and risk-sharing, we only improve the relative position modestly.

Here you see also the two graphs that I showed yesterday. If you -- the light blue line represents the target rate of return which corresponds with 20 percent of the projects in the world being worse and 80 percent of the projects in the world being better. If you look at the status quo that is below that light blue line, at least for the Alberta project, and if you -- and all we do with this stranded gas contract is to add 2, 3, or 4 percentage points to the rate of return, depending on what the gas price is that you are assuming.

So, we are increasing modestly the rate of return of this project. It is very difficult to improve the rate of return of this project, because all the capital is up front, and it is such a gigantic project.

So, an important aspect of the structure here, you see the Chicago project, Chicago project, as I said yesterday, is very unattractive from a rate of return point of view under the status quo. And even with the contract, it is not very attractive compared to what target value for the world would be.

So, consequently, with this contract, we improve the rate of return. We increase significantly the probability that the project will come about, that on project sanction date a positive decision will be made. But it is a modest improvement.

And, as you can see here, really, the Chicago project as well as the Alberta project, kind of stay around this target value, and this means that the chance that these other smaller, more profitable projects will nibble this project to death is very high. And that is why this rate of return is -- is so important.

Let's now look at net present value. Net present value has been thrown around as a term. It may probably need some explanation. What is net present value in the first place? It is something like economists love to talk about. But what -- what is net present value?

Net present value really is what you pay today for something that is received tomorrow. Let me give a simple example. Say suppose you have a friend, and he says, Here it is. I have a promise -- a promissory note of $1,000. Next year, May, I'm going to be paid $1,000. But I need the money now. I need the money today. Could you please pay me something today and I assign that promissory note to you?

Now, if a friend would come to you and say, Here is this promissory note of $1,000. What would you pay today for that note?

Now, if it is a good friend, maybe you pay $950, because that's the interest rate. If it is not so good a friend, maybe you pay $800 for the thousand. And then you have a good deal.

So, consequently, that is called the present value. How much do you pay today for what that money is tomorrow?

If we talk about an NPV 10, it really means that you are paying today $910 for the thousand dollars that will be received next year. That's -- that's all it means. It means that you're willing to pay with what is called a discount rate of 10 percent, 10 percent off, relative to what the value is next year. Or, rather, it is like building up your 910 with 10 percent.

The oil industry typically uses this 10 percent discount rate, and why -- why do they use a 10 percent discount rate? Because this is kind of the cost of capital, plus a certain risk margin. So what do you -- what is the cost of capital? Whatever you borrow for it, whatever you -- return you like to make for your shareholders, plus a little bit of a risk premium. That's basically where this 10 percent comes from.

So, that is the net present value. Net present value is a very important indicator for the oil industry, because it expresses the value of the whole deal. For instance, say, suppose Exxon would want to sell out to another oil company. After this deal is done, they say, Okay, actually, we'd like to sell out to Shell, say, and we sell this whole deal for cash. What would they get? They would actually get -- I mean, depending on the negotiations, of course, but they would use the net present value to determine what they will get.

So, consequently, that is a very important value. It illustrates how much this deal is worth on the market if you actually want to sell it to somebody. So, that is the net present value. A very important indicator.

Here, you see the same string of beads with the net present value of the Alaska project plotted on it. What you see is if there's a low price, the Alaska project is among the worst in the world. Or, in other words, if you have $15, this project is a dead duck, as you can see from this graph. You lose your shirt. That's -- that's what that graph shows. The green doesn't matter whether you have a stranded gas contract. It doesn't matter, status quo. Either way, this project is a very bad project. That is what you see. The green, the red, and the blue are all the way, they are -- they are the worst. They are negative relative to the rest of the world. There are very few projects around the world that are that negative under low prices.

So, here you see -- here you see the risk that we talked about yesterday. This is assuming no cost overruns. Now, if you add the cost overruns to this, then this becomes even worse.

So, this gives you an idea of the immense risk of the project.

But now look at the high price. What -- what happens at 60? At 60, this project is the best project in the world. So, here you see the unusual economic characteristics of this project. At a low price, it is the worst project in the world. At a high price, it is the best project in the world. Take your pick. What do you do as an investor?

Here you see that this deal has to be balanced. This deal has to be such that the high profits are balanced against the high risk. That -- this graph illustrates the most difficult part of this project. You either go broke or you have a monster profit or something in between.

That is what makes this contract so difficult. That is what makes this project so difficult. The risk balance is so difficult.

And that is what you see so well demonstrated on this graph. If you look at the green, red, and blue -- and blue markers at the very high price, all the way to the right-hand side, wonderful. You could sell this project if -- if you would absolutely be certain that the oil price was going to be $60 a barrel from now on, you could sell this project for $25 billion. That's a good value.

But if the price is $15 a barrel, you have to give somebody $3 billion to take this project on. So that -- that gives you an idea of the immense differences in profitability of this project in total size.

So, how do we improve the net present value on the left-hand side without really affecting the net present value on the right-hand side? The answer is: Very carefully. We'd like to improve the net present value on the down side, but not so much that it becomes even an extra windfall on the up side.

So, how do you do that?

The next graph shows that. The blue line is the target value, and, as you can see, as soon as the price goes up, the net present value becomes far more than the target value. And what you see here is the contract compared to the status quo. And it's a very interesting line, actually. What you see here is that we added actually a constant amount to the net present value. We added a constant amount. We didn't add a percentage to it. We added a constant amount to it. And why was that? Why did -- is the contract structure that way?

That is to make sure that under the low prices the contract becomes much more attractive, but under the high prices, you don't have to give. So, consequently, by adding a constant amount to the project rather than a percentage, you achieve precisely the result that we only give what is necessary to make the net present value attractive on the down side, or not attractive, less unattractive on the down side.

So that is the -- that is the whole philosophy. We only tried to give for each profitability indicator the minimum necessary to make this project a go. That's the whole philosophy. So that is what you see here.

The Chicago project is horrible under the status quo under low prices, as you can see from the net present value. In fact, it is negative, and it is practically zero under the status quo at $3.50. So, if you actually have to bring all your gas to Chicago, the net present value is -- is very unattractive.

And, again, just as with the Alberta option, you see that we're trying to add just enough of this net present value to make this project a go on the down side. That's really the philosophy of how we changed the net present value of the project.

That brings me to the net present value per barrel of oil equivalent. As you well saw from that previous graph, the net present value flip-flops from the worst project to the best project, but the main reason for that is that it is such a large project.

So, if you really want to compare the net present value, how attractive is the net present value, what you have to do is look at what we call the net present value per barrel of oil equivalent. Let's see how much value there is per barrel of oil equivalent, relatively speaking.

The next graph is the same string of beads that shows the net present value per barrel of oil equivalent. Now, this is a totally different story. As you can see, as the price goes up, the Alaska project gains relative to other projects, but not much.

So, irrespective of the price, if you look at the net present value per barrel of oil equivalent, the project is still below an average net present value per barrel of oil equivalent. If it is below or it is on the high side, if it is very attractive, these -- these squares and dots go all the way down. So, we're still above the 50 percent line. We are even above the 60-percent line. So that shows that you are still in the lower 50 percent of the projects.

So, consequently, although the net present value under high prices could be absolutely -- absolutely gigantic, on a per-barrel equivalent basis, it is okay. It is an attractive project, but it is not a wild story. And that is what you see here.

In this contract, what we are trying to do with net present value per barrel is exactly the same as what we did with the net present value, because that is directly a ratio, and we are literally adding precisely 19 cents net present value per barrel equivalent to make sure that this project is economically attractive on the down side. So, that is what you see here.

So, this is the net present value per barrel of oil equivalent, which is zero if you have the 2.50 price, gets to about 40 cents under the contract, and 20 cents under the status quo. If you are at $3.50, which we used as our low-price forecast, and then it starts going up quite remarkably.

So, that is how we tailored the contract to this particular profitability indicator. And as you can see from this graph, what we are trying to do is improve the contract exactly enough so that we don't give more net present value away on the down side than we absolutely have to.

This is the Chicago project, a very bad project if -- if we need to go to Chicago at low prices without even cost overruns.

That brings me to the next profitability indicator, PFR 10. What is that? What is the profitability ratio? Oh, that's another very easily understandable ratio. The ratio is 2, if you give me $1 and I give you $2 back. It is that simple. So that means the profitability ratio is 2 if you put in a dollar and I give you a dollar back, plus a dollar profit.

So, if the ratio is 2, we are doing okay. If the ratio is 1, it means you just got your dollar back. That's not particularly attractive.

Now, again, what we do is we bring the value of time in this ratio to -- to count for the time loss. And, again, it is discounted at 10 percent.

So, consequently, that is how this is measured. The capital stream is measured at 10 percent. The net present value is measured at 10 percent.

So, it is a very simple ratio. This is actually the ratio that illustrates the margin of this project. It is a very important ratio for comparing projects around the world. Because it illustrates what a company is actually doing for its shareholders. What a company is doing for its shareholders is how much margin do you make on top of the capital. That -- that's really very basic. And, consequently, that is this profitability indicator.

Now, on the profitability

indicator, we're doing great. If the project -- if the price goes up, even under status quo conditions, as you can see, these green blocks come all the way down. So the profitability indicator, even under the status quo, under high prices is quite attractive. Under low prices, as you can see, again, the same story, quite unattractive. But, the profitability indicator kind of flip-flops just like the net present value.

What you see here is that the participation by the State -- there is a huge difference here between the green blocks and the red and the blue. You significantly improve the relative position of this project with this State risk-sharing and participation in terms of this profitability ratio. It is this ratio that really is so important to make this project a go. Because, as I said, this is probably one of the most important ratios that companies look at. It is a very good ratio to compare projects around the world.

And, consequently, this is exactly what that participation does. It may not improve the rate of return dramatically, but it definitely improves the profitability ratio dramatically. And that is a very strong incentive for the companies to go forward with this project.

And here you can see that we are really targeted, the State participation, to achieve this precise result. This is a very important ratio to significantly improve the chances that this project will go forward.

And, as I mentioned, this is practically singlehandedly created through this 20 percent risk-sharing and participation.

Here you see the improvement in profitability ratio relative to the status quo, very significant. As you can see, at $3.50, the profitability ratio for the status quo is just over 1. It is about 1.10, something like that. That mean that that's unattractive. If you go to 2.50, it is actually below 1; so that is very unattractive. But at 3.50, we improve the ratio just enough that even at low prices, this is actually quite attractive, and then as prices go up, this ratio becomes quite attractive. And that is really what will boost the chances of this project.

And the beauty is, as I explained yesterday, we're not giving anything up for this. This -- this is just because of the State risk-sharing and participation.

As I said, the profitability ratio is quite attractive for the Alberta project. And why is that? Because that requires much less capital than the Chicago project. Profitability ratio doesn't look that great, as you can see here, for the Chicago project. And it is, therefore, that this participation by the State, all the way to Chicago, if we participate for 20 percent, means all the way to Chicago, is so important because that is what will improve this profitability ratio so much if we would have to sell, if we would have to invest in infrastructure to bring it all the way to Chicago.

That brings me to another indicator that economists like to use and it's kind of similar to the net present value, probability indicator. But this is the net present value for undiscounted Capex. Now, why are companies looking more and more at this ratio? The undiscounted Capex is probably the best measure of the total amount of effort required by a company. It is undiscounted, so it is not discounted as the -- as the PFR 10 did.

This -- this Capex represents what do you need to mobilize as a company? What do you need to mobilize in effort to get this done?

These days, that is a very important indicator. And, consequently, companies start to look -- since there is so much stress on human resources and other resources, companies start to look, these days, more at this -- this indicator. It didn't used to be. We almost never looked at this. But these days, this is becoming an important indicator. And here you see kind of the same story as with -- I -- I didn't have a graph from PFC Energy, because, unfortunately, there was an error in it, and I -- therefore, they're still repairing it.

The profitability indicator of NPV for Capex, as you can see, improves the project quite significantly for the Alberta project. And it provides an absolutely crucial improvement, as you can see on slide 21, for the Chicago project.

So consequently, under the Chicago project, if you have a status quo condition, the conclusion, even up to 5.50, even up to 6.50, it's just not worth to do this project. The amount -- the total amount of capital, the total amount of effort required for the meager -- and relatively speaking, meager NPV that comes out is just not worth it. And consequently, that is why it is so important to improve this indicator. And the State participation and risk-sharing is precisely doing that, without giving up revenues on part of the State.

Net cashflow. Yesterday we discussed the net cashflow at some lengths. What is the net cashflow? That's exactly what it is, the amount of cash that you get out of this project after you have deducted all of your operating costs and all of your capital costs. Actually, the total net cashflow is not really a profitability indicator as such, because the net cashflow doesn't necessarily expresses a measurement of profitability. Nevertheless, companies consider the total amount of net cashflow very important for strategic reasons. A high net cashflow secures the long-term future of the company.

So, the net cashflow is an

excellent way of looking at the long term. Most of the profitability indicators are short-term, are medium-term, look -- look at the near future. The net cashflow is a deep future measure. It says how good this project is for the long-term survival of the company. If you have a huge cashflow over the life of the project, you can count on that forever and ever. And that is so important.

This graph I showed yesterday. We for sure don't have problems with this project with the net cashflow. The net cashflow is fantastic, no matter what the price is. This is a very huge net cashflow. As you can see, even at low prices, you're still the best in the world. So, consequently, the net cashflow is a very positive strategic aspect of this project.

And consequently, if companies have to agonize about the downside and have to agonize about whether they can take this risk that the net present value may flip-flop to very low levels, at least there is one good point. That is, no matter what, the net cashflow of this project is very attractive. And consequently, that is a very strong under -- strategic underpinning of this project.

Here you see the difference between the status quo and the contract. Now, as you can see, you cannot actually see the status quo, because the status quo is exactly under the red line. And what does that mean?

That means we don't give up any cash. The cash is the same under the status quo and under the proposed contract, no difference in cash.

And why is there no difference in cash? Because the cash is good enough anyway. Why should we give more cash?

So, consequently, that is the reason why we improve the rate of return, but not the net cashflow. There's no sense giving more cash away. The cash is more than adequate.

So, that is why this deal is structured the way it is. As you can see from these graphs. Very different impacts.

Just as with the patient, he doesn't need vitamin E. So don't give him vitamin E. Give him vitamin A. And this is what they're doing here. They're -- no improvement in cash. It's not necessary. But improvement in rate of return, because it is necessary. That is how this deal is structured. Even for the Chicago project, cashflow is more than sufficient. No problem with cash.

And you can simply say, Now, this is -- this is probably because this project is such a large project. And that's true. The cash is huge because this is a large project. But, let's look at the next one. Let's compare the cash of this project with the cash from other projects around the world on a barrel equivalent basis and see what happens. What is the reason for the high cash in this project?

What you see here is a very interesting graph. The net cashflow per BOE, actually even on the low price is quite good. So, even if you correct for the large size of this project, the net cashflow per barrel equivalent under low prices is quite good.

Why is that? Why is this such a project that has such a high cash under low prices?

The answer is very simple. The operating costs of this project are so low. If you have to develop an offshore oilfield or if you have to develop a gas field in the McKenzie Delta, you have to spend considerable operating costs. And these operating costs go straight off the net present value per barrel of oil equivalent.

The great advantage of this project is that the gas is already found and it doesn't cost a cent more to put it in the pipeline rather than injecting it in the ground. In fact, it is cheaper to put it in the pipeline rather than re-injecting it in the ground. So, consequently, the operators -- no additional operating costs on 22 tcf of gas. That is what makes the net cashflow per barrel of oil equivalent so great.

Now, if it is so great, we don't need to improve it. This project is already okay in terms of net cashflow per barrel equivalent. And that is exactly what we did. Again, you can't see the status quo because the net cashflow per barrel equivalent is exactly the same under the status quo in the proposed contract. There is no need to improve the net cashflow per barrel of oil equivalent because it is already a low operating cost project of tremendous size.

The same is true for the Chicago

project.

The summary of this is that what I have hoped that I have demonstrated this morning to you is just as the doctor precisely gives the right medicine for each symptom, that is how we have precisely structured this contract so that the weak symptoms of this project are improved, and the strong symptoms of this project are not improved.

So, consequently, the whole fiscal package is targeted specifically to make this a healthy patient. It is not targeted to give money away, nor is it targeted to make this project a healthy patient. Exactly the right medicine for each of the seven profitability indicators that we evaluated. That is how this contract is structured.

Let's review that. The rate of return is improved over the entire price range because we need to improve the rate of return over the entire price range.

The net present value at 10 percent is targeted to provide improvement for low prices, but not for high prices. The same for the net present value per barrel equivalent.

The profitability indicator is targeted in such a way with the participation of the State all the way to Chicago, that we precisely solve the problems of a weak project going to Chicago. The same is true for the net practice value per Capex. No improvement in net cashflow because it is not necessary, no improvement in net cashflow for BOE because it is not necessary.

This is the structure of this contract. This is the economic structure of this contract.

How was this achieved? What are the essential medicines that we use to make this patient a healthy patient?

Firstly, as we mentioned already, State risk-sharing and participation -- 1, 2, and 3.

The 35 percent credit on the GTP and the feeder lines is an essential component to improve the rate of return.

Then we have the upstream cost allowance. We have this upstream cost allowance of 22.4 cents. What is this cost allowance doing? This cost allowance is specifically targeted to improve the net present value at low prices. That's the reason why it is there.

Remember, the NPV per barrel equivalent or the NPV at low prices is not good enough. So this upstream cost allowance is precisely introduced to protect the project under low prices.

And then we have reformulated the midstream property tax in such a way that, as you could see, that the State no longer participates in the midstream property tax. It goes only to the communities. So, there is less property tax on the pipeline. That means the wellhead value is higher, because the tariff will be lower. Again, another methodology of improving the net present value under low prices, but not in any significant way under high prices.

Here are the four medicines we are using to make this -- this patient healthy: State participation, 35 percent credit, upstream cost allowance and reformulation of the midstream property tax. That are the four essential ingredients that are the underlying structure of the proposed contract that you have in front of you.

Thank you so much.

[Applause]

COMMISSIONER CORBUS: Thank you, Dr. Van Meurs.

We will break for lunch. Please be back at 1:30 sharp. Thank you.

[Lunch break]

COMMISSIONER CORBUS: Would everybody please take their seats so we could get going?

May I have your attention, please?

Everybody should have in front of them a copy of -- of all the PowerPoints that were presented this morning and are going to be presented this afternoon.

We have two presentations this afternoon, both by Dr. Van Meurs. The first is on fiscal certainty, and the second is the analysis of the deal, Alaska revenues.

The first presentation is a very short presentation, we figure about 20 minutes. The second presentation is longer, maybe an hour, or a little bit longer than that.

We're going to have Dr. Van Meurs go through the first one and start on the second one, and we'll see how it goes, whether we should push on through before we take our next break or whether we break in the middle of it and take a break then.

In any event, afterwards, we will have a break, and then -- then we'll answer questions. We've got quite a stack of questions have come in during today. So it's going to take a while to answer them all.

So, with that, we'll turn it over to Dr. Van Meurs.

DR. VAN MEURS: It is a great pleasure, again, to now explain the next topic of -- of these presentations. And what I'd like to start doing is introducing the concept of fiscal certainty and -- and what the rationale was for it.

Of course, all during the presentations over the coming nine days, the matter of fiscal certainty and all of its dimensions will be discussed in much more detail. But I, for sure, would like to kick off a few really important issues.

Firstly, particularly as to why we need it, basically, from an economic point of view.

The first thing that -- that I'd like to highlight is that we don't need fiscal certainty because Alaska is in some kind of an unstable regime or something, political regime. That is absolutely not the case.

Alaska, over the years, has provided great stability for investment to investors in a very responsible manner. The last change that was made in taxation was in 1989, and that was a modest change. And I think the last time before that was 1977. So, consequently, Alaska definitely is not changing fiscal terms at a rate that is faster than, say, other jurisdictions in North America or in Europe. And consequently, from that -- from that perspective, then, we don't need fiscal stability because of political risk. That is absolutely not the question.

We need, in this deal, fiscal stability because of the highly unusual risk balance that I have already discussed with you earlier this morning.

As we saw this morning, the net present value of this deal flip-flops from a project that could be the worst project in the world to a project that could be the best project in the world in terms of total amount of profits. And it is always very difficult to make decisions on a project like this.

Four years from now, when all of the feasibility work has been done and the regulatory process has been completed, the investors will face a very difficult decision to go either forward with this project or not.

And, typically, at that point in time, the investors will consider the entire risk/reward balance of the project.

Hopefully, between now and four years from now, a lot of the feasibility work will allow us to reduce the cost of the line, to plan the line better, to maybe look for new technological options like different dimensions or different steels, and other factors that will bring the cost of this pipeline down. But nevertheless, no matter what happens, even four years from now, the investment decision will have to be based on the possible economic developments that may take place, then, in the subsequent 40 years. And, consequently, that is always a very difficult position. No matter what we do, four years from now we will still be faced with a project that could be the worst in the world or the best in the world, depending on economic circumstances.

And in that kind of decision, the investors have to be absolutely certain that if prices turn out average or high, or if costs turn out less than expected, that the investors can count on these profits, that they have to be sure of them. Because it are these profits that are going to be weighted against the losses or the negative project performance if there are cost overruns or low prices.

So, it is because the investors have to strike this very difficult balance and make a decision on an extremely difficult risk profile that we have fiscal stability in this deal. It's not because Alaska is a politically unstable area. It is not. It is, in fact, one of the most political stable areas in the world. But it is the inherent nature of this project that requires this.

There are two plausible fiscal certainty scenarios that we need to consider and that could have a very important impact on this project. The first is the famous gas reserve tax that's been discussed intensively among Alaskans, and the second one is possible changes in the fiscal terms.

Let me start with the gas reserve tax. An important decision needed to be made whether fiscal stability would be provided relative to the gas reserve tax. In other words, would the contract state that the producers are not subject to the gas reserve tax, or would that be an open question? That was the point. That was the two scenarios that were compared.

So, that is what you call a study in comparative economics -- a study whereby you, on the one hand, look at the option without fiscal certainty as far as the reserve tax is concerned and the other with fiscal certainty and protection against the reserve tax. Now, the reserve tax is, of course, on the ballot, but it hasn't been passed in a particular law, but I made assumptions as to how possible reserve tax law may unfold.

As you well know, the gas reserve tax involves a payment on the gas in the ground, maybe 3 cents per mcf, and only on particular fields. Not on small fields, not on new leases. And then if the gas actually starts to flow, then this law would be automatically repealed so there would be no further tax payable, and then the idea is that whatever has been paid before could be recovered as a tax credit against the production tax.

Now, the amounts of tax that we're talking about here are very, very considerable, 3 cents on 35 tcf of gas in the ground. That -- that's somewhat over a billion dollars. So this is a monster amount of tax per year to be paid if this law would apply.

I actually calculated under different gas prices, as you see here, how much would be paid and how much could be recovered because there is actually a time limit on the recovery -- how much could be recovered, say, under different gas prices. And, of course, if the gas price is low, in my model, I assume eight years -- that means you have paid 8 billion in -- and then, of course, you can recover some of it back. If the gas price is low, there is just not tax credits enough to significantly recover these payments. Even, my calculations show, if the gas prices are high, even at 8.50, you cannot completely recover the reserve tax.

So, no matter what, the net effect of this tax is that this will be an additional tax on the project, somewhere between 7 billion and $3 billion.

The most significant aspect of this tax is the time value of money, because it has to be paid during the evaluation and construction period. The tax would start right away. It is not something that comes into being if the gas was already flowing. It would start right away, and it would be recovered when the gas starts to flow.

If you do the economics on the case with a reserve tax, as you can see on slide No. 10, then the rate of return of this project with this highly regressive tax will be absolutely dismal, as you can see. This tax makes the project uneconomic, period.

So, if this option is chosen, if we would have a contract that would say you are subject or you may be subject to this tax, then companies would assume that they would be subject to the tax, and they would plug that in their economics. And that's, then, the end of the project, because it is completely uneconomic under these circumstances.

And consequently, that is a very important reason why the proposed contract includes fiscal certainty with respect to the reserve tax. It is absolutely essential for the future realization of this project that the investors are protected from this tax. This, of course, is a very difficult issue, but it is very simple. If you compare the economics with and without tax, with tax, this project is dead.

I know that maybe the people that are -- are proposing this tax think that this will be a way of getting the project going. In fact, the exact opposite will happen.

Apart from an enormously negative impact on the project on a comparative basis, it is my belief, having looked at -- at legislation, that it will have a dramatic impact on investors around the world.

A provision in the law in a proposed concept is: If you don't want to pay the tax, you just give your leases back. That is kind of like saying, "Now, from now on we tax you $100,000 a year on your home, and if you don't like to pay it, you can always give the home to the State." That is de facto confiscation of property, and that is how it would be interpreted internationally.

We have just gone in Bolivia through a very dramatic period. For me personally, a very difficult period. I was advisor to Bolivia for years. I helped build the new petroleum law, and I helped build the privatization of the national oil company. And as a result of that, the country found 50 tcf of gas and suddenly had a new life for the future.

However, there were very strong forces in this country and very strong forces from the native and indigenous population, which is very large in Bolivia, which is really not participating in the economic wealth of the country. And the leader of the Coca Leaf Union, that produces the coca leaves, Evo Morales, became president of the country. And, as you saw in the newspapers, he decided to nationalize the oil industry, the gas industry. The country will not recover from what happened during the last few weeks for the next 20 years. Investors will take a long time to come back.

If the reserve tax passes, it will have the same impact. It is a very serious matter. This is not just a funny political debate. This reserve tax could destroy the future of Alaska for many years to come.

I have experienced those conditions personally in Bolivia. I know what happens if you de facto confiscate property. It is a very, very serious matter from an international perspective.

And that is why it is absolutely essential that the Legislature, in approving this contract, stands up and realizes that this reserve tax cannot pass. If the voters want it, then there should be protection in the contract. It is a very difficult matter. I'm happy I'm not in your shoes. Very difficult political matter. If the people of Alaska want the reserve tax, how would the Legislature say, You can't have it? Very difficult. I understand the difficulty.

But, the economics is clear: If the reserve tax passes, no gasline. The companies will oppose it to the bitter end. So, that is why it is very important. That's probably the most single, most important political decision that you will be making if you are considering this contract. A very difficult decision.

Apart from the reserve tax, the contract protects against fiscal change. And in order to study the fiscal change I looked at a hypothetical contract where there would, say, be a reopener, where the Legislature could reopen the contract at the commencement of operations. And I said, Okay. Let's just assume that we have a contract, but that we will just look at the economic situation ten years from now, and that we have a reopener to the contract, and that, at that time, the Legislature decides what the amount of tax gas is, for instance. So I used the tax gas as a variable.

And I looked at cases that would be plausible. Say, suppose gas prices stay high. I showed you the enormous net present value of this project, if prices are high. Ten years from now, the net present value will be significantly more. Why? Because the capital will be of some cost at that point in time. And we are ten years closer to the start of the cashflow.

So, ten years from now, when this project starts, you would be looking at a huge cashflow with an immense net present value. And if there was no fiscal stability, it is plausible that a reasonable Legislature would come to the conclusion at that time that maybe 20 percent tax is reasonable or 40 percent tax is reasonable, rather than the 7.25. These are still numbers within the government take range, like Norway or other countries in Europe and North America. So, this is not outside the reasonable range.

So, consequently, I analyze these cases and say, How would -- how would that -- how would such a hypothetical decision impact on the project? And here you see it. I calculate the -- recalculate the rate of return, first on the Chicago project. Of course, under the Chicago project it would be very dramatic, because the rate of return is already below what we need. A 20 percent tax ten years from now, at the start of the line would knock down the rate of return risk 2 percentage points or so. A 40 percent tax would almost knock it down by 5 percentage points.

So, if the companies would have known that that was going to happen, it is unlikely they would have done the project.

The same is true for the Alberta project, but not as dramatic, because it is a more profitable option. 20 percent tax would place you exactly at the target rates. 40 percent tax would place you well below the target rates.

So, consequently, what the investors face is that if there is no fiscal stability on these gas terms that ten years from now taxes may be changed, not necessarily in an unreasonable way, in a plausible way, but in such a way that very significant value would be eroded if conditions are positive, like high prices or average prices and low cost.

So, now they lose both ways. Now they end up with a marginal project if conditions are good, and they end up with a bad project when conditions are bad.

For a giant project with the risk of the Alaska gas project and the size of the Alaska gas project, investors can simply not take that kind of risk. And it is for this reason that we have fiscal stability in the contract.

I gave you the examples on gas. Now, there is also the discussion on fiscal stability on oil. Why is there fiscal stability on oil? Now, firstly, to begin with, all the new gas that needs to be discovered or developed, like Point Thomson, has very large amounts of condensates in it. The 9 tcf yet to be discovered, and the 8 or 10 tcf in Point Thomson would probably have 800 million, maybe even a billion barrels of condensates in it. That's a very important underpinning of the economics of this project. So, you need absolutely to include the condensates in this fiscal stability.

But apart from that, it goes further. Really, Prudhoe Bay and -- particularly and other fields in the North Slope are continuing to produce oil as well as gas. And, consequently, if there would be unusually profitable events unfolding on the gas side, even with fiscal stability only on gas, it is possible that the Legislature would say, Okay, then we take it out on the oil. And that is the link to the oil. The link to the oil is not because the oil itself is part of the investment decision to put the project forward, yes or no. It is part of the overall fiscal environment.

Why? Other speakers will -- will enter into that question in more detail, but it was already asked, so why don't I discuss that somewhat.

Why is there 30 years on oil and why is there 45 years on gas? Obviously, if you do economic analysis of the type that I present to you here, a cashflow 30 years from now on a 10 percent discount rate is not very valuable. So, consequently, after 30 years, if you do different fiscal scenarios, you could increase the tax gas with a very high number and it would barely make an impact on your rate of return or net present value. The longer you go into the future, of course, the less -- the less big the impact is on the investment decision itself from a profitability indicator point of view the way we evaluated profitability indicators this morning.

However, as I mentioned, the project, beyond the mere profitability criteria, has very important strategic importance for the companies. For oil 30 years is enough. International contracts indicated if you want to make new decisions to relate to oil, if you want to develop heavy oil along with the gas, if you want to develop condensates along with the gas, internationally, 30-year contracts are fine.

For the case of the gas itself, there has to be a more strategic view. And the strategic view is that in addition to the mere profitability indicators, as I mentioned this morning, the cashflow serves as an anchor for this project. Dramatic change in gas fiscal terms 30 years from now would have a dramatic impact on the anticipated cashflow, because that is an undiscounted cashflow. And, consequently, fiscal stability for a longer period on the gas has immense strategic value for the companies, has immense strategic value for the long-term future of those companies.

And, consequently, that's the reason why we're considering 45 years in the contract for gas, not because that affects, say, the rate of return or the net present value very much, that it affects the cashflow very much. But there is an even more important aspect than this, which is also mentioned already by the Commissioner in his finding. And that is, I'd like to remind you, this pipeline is not full. I happily present to you rate of returns on nonexisting gas. We still have to find that gas. And that gas can only be found if people that find that gas have 30 years of fiscal stability, and that means if people that start to develop gas 10 or 15 years from now can count on these terms. And that is why there is 45 years for gas and 30 years for oil.

So, that was a somewhat longer explanation. Other speakers will discuss these matters in more detail, but since this was an issue that was brought up already during private discussions, I felt it was probably good to dwell a little bit, at least from the economic perspective of this time period in this fiscal stability discussion.

That, basically, ends the fiscal stability discussion. What I would propose, as the Commissioner said, since this was a relatively short presentation, I'd like to just get started on the fiscal revenues, but after you have seen your first 20 slides, you will probably need an extra coffee. So what I'm going to do then is maybe break halfway and then we can pick up the remainder of the presentation a little later. So what I'm going to do is, then, now start with the next presentation which actually now relates to: What is it that the State and the affected municipalities will get out of this deal?

If you repeat slides from the first day. As I mentioned before, the total Alaska revenues received under the contract are approximately the same as under the status quo. But there are some important wrinkles on this, which I now would like to discuss in more detail.

This was the graph that I showed yesterday to show that the income to Alaska is really the same either way. If you measure the total income, it is the same either way, under the proposed contract and the 2005 terms. And I showed this table also to indicate that actually, if you look at it in more detail, there is about an 8- or $900 million difference between the contract and the 2005 terms.

And this was the next slide that I showed yesterday, just for those of you who were not here, to show that even under low prices, even under 2.50, as low as 2.50, the revenues to the State would be very, very significant.

So, this is a contract that will bring in very, very significant revenues. This is in constant 2006 dollars, so the nominal dollars will actually go up as you go along.

Let me now discuss this picture in a little bit more detail. As the Commissioner already mentioned: Why are the revenues the same? Well, very simple. There's no change in royalty rates. No. Royalty is already half the Alaska income right there. Half the income typically comes from the royalties. So, no change in royalty rates. The tax gas rate of 7.25 percent is about the weighted average of what would come out of Prudhoe Bay and Point Thomson, and, consequently, that's about the same.

And then corporate income tax, no change either. So, in the three big blocks of revenues to the State, there's no change, essentially. So, no wonder that the income to the State is the same either way. That is easy to see.

Then what did change? There are some important changes, but what are the details of the change? The proposed package, as I explained this morning, is clearly different. It has different elements, because we needed to give the right medicine to this pipeline project to make this a a healthy patient. So, what did change? That's what I'd like to show you here in a somewhat complicated table. But this is an important table.

On the left column, you see the 2005 fiscal terms. We call it the 2005 fiscal terms because we didn't know whether the PPT was going to pass, and if the PPT would have passed, that would have been the new status quo, of course. So, consequently, to avoid confusion, we talk about the 2005 fiscal terms in the proposed 2000 contract. Now what you see there is that -- and the 2005 fiscal terms includes all the features that I described for you with respect to the status quo.

What you see here, this is just -- I -- I just gave one case. It is very similar for all of the cases. This is for the Alberta project, the project ending in Alberta, and for $5.50, which is our average price forecast. So, this is how -- this is kind of a very likely outcome of -- of the deal.

What you see here is that under the fiscal terms, the royalties and severance tax, the total value of the State gas would have been 34.3 billion, and under the proposed contract, it's 34.6 billion. This is slightly more. Now, why is it slightly more? Because we've lowered the pipeline tariff, so the value of -- of the oil and gas is becoming slightly more. At the same time, the 7.25 is slightly better on an undiscounted basis than the -- say, the existing system.

Then under the proposed contract, as I promised you this morning, I deduct the 5.5 cents per million Btu, so I deduct 488 million, just marketing cost. Now, as I indicated, I believe this is a very conservative number. Companies have already indicated that we can probably conclude long-term deals on 1 cent. So, this is a high number. But, as I said, I -- I'd like to include a conservative number.

Then comes a very important number that I mentioned this morning, and that is the upstream cost allowance. And the upstream cost allowance is 1.8 billion, and, consequently, that has to be paid for the gas -- the State gas as the State receives it, the 22.4 cents. That's a big negative. So that brings the value of the State gas down to about $2 billion less than under the 2005 fiscal terms.

As I explained this morning, this UCA or upstream cost allowance is, and particularly there, to protect the net present value of the project under low prices.

Then comes the net profit share on Point Thomson, which is the same either way. With no change in the net profit share, it will simply be paid. So, no matter what you assume about that net profit share, it is the same number in the two columns. It will be paid in cash based on current agreements.

Then, under the proposed contract, of course, we have the net cashflow from the pipeline tariffs, 2.9 billion coming in.

Then, under the North Slope tax you see that the North Slope tax is actually somewhat less than the current situation, and that is largely the result of the fact that under the proposed -- under the 2005 fiscal terms, I assume CPI inflation, while under the contract the inflation rate is a little bit cut down, and that creates a somewhat lower total tax.

The midstream has a significant increase in tax. You see it going to 1.2. Although some of that actually belongs to the State, I put it all in the muni column here, not to make the table too complex. But why is there such an increase? Because what we actually did is we changed this property tax from something that declines yearly because the value of the pipeline declines, to something that stays constant over time. And, so, consequently, in total, this is really a much better deal for the municipalities. In the coming days, Dan Dickinson and others will explain to you the -- in utmost detail, of course, this whole municipality issue.

At the same time, the State is not participating in the midstream property tax, except for some wrinkles that Dan will explain. So, because the State almost threw in its share of the property tax, the property taxes are about a billion less.

The State corporate income tax is about the same. Of course, it calculates differently if you have all these other different figures, but the rate is exactly the same in the upstream.

And then in the midstream, the State receives less. Now, why is that? Because the State corporation that is investing in the line will not be taxable. So, consequently, actually, there will be a slight loss of corporate income tax, the midstream.

Then you see the GTP and feeder line credit that I talked about, which on a real basis is worth 788 million, if you use my capital cost.

So, there you see that there are pluses and minuses. Of course, the important minus is the UCA. The important plus is the net cashflow. Another important minus is that the State throws in its property tax on the midstream, and another important minus is that the GTP and the feeder line credit are included. Now, as I explained this morning, the GTP and feeder line credits are included because of their very positive rate of return effect.

So, here we are. That explains that in total the proposed contract would end up with kind of 800 million less than the 2005 fiscal terms.

Over the coming days, particular Dan Dickinson and others will explain to you, of course, in a lot more detail the inner workings of each of those -- each of those features. But I thought it was good for you to explain how the total fits together. Because we mention all of these features, and I say in total it is about the same, but there are these important differences. And it is important to realize where these differences come from.

So, although the total ends up to be the same, the inner structure of the deal, where that money comes and goes, is actually somewhat different. And the reason for that I explained this morning already.

So, as you could see, doesn't matter for the Chicago project or the Alaska project. The income is about the same.

Interestingly, on the Chicago project the income is actually somewhat more than on the current 2005 terms. And the reason, of course, is that there's more pipeline income, because this is a bigger -- a longer project.

So, interestingly, revenues on the Chicago project, because of the State's net cashflow -- higher net cashflow will be higher than the 2005 terms.

Now, there are still documents that are still being worked on. I mean, you have already your 900-page binder, but over the coming months before you have to final -- before you see the final contract, other documents will still be prepared. In the fiscal interest finding, we describe, for instance, the LLC agreement, the agreements that actually underpin all this pipeline income. And, of course, those agreements will be made available in the future.

There will also be what is known as a coordination agreement, because, basically, we need to make sure that the parent companies of the -- of the Alaskan companies make sure that their Canadian counterparts also adhere to the pipeline clauses under this -- this agreement.

So there will still be all kinds of documents coming to you that are more detailed and that will be made available as we go along, and, of course, most of that will be ready, say, in the near future. But that -- those documents had been described in some detail already in the fiscal interest finding, and, consequently, I think you have already -- have already a good idea of what these documents are going to include.

So, the State income on the pipelines is actually coming from what is called LLCs, limited liability companies, where the State will participate for 20 percent. Or, in other words, the State will not pay itself from the tariffs. The State -- its shipping commitments of the State will go into the joint LLC, in the joint LLC company, and then the State will simply get 20 percent of the revenues of this joint LLC company no matter who transports the gas. So, consequently, it is not that the State has to pay for its own gas or is -- is -- there is no direct link.

So, consequently, the State pays into the LLC company. The State then receives from the LLC its proportionate share of the revenues. And that proportionate share of the revenues is higher if you go to Chicago than if you go to Alberta because of the longer distance.

What I didn't dwell on so far, and

that's a very important issue, is the time distribution of these revenues, although in undiscounted amounts, the revenues are almost the same. We have dramatically not only moved items from one column or from one row to another row, we also have shifted the items very significantly in time. Because, as I said, by being participants in the project, we actually have a negative cashflow right in the beginning and then make up for it later.

This is what you actually see here. Here you see, for $5.50, the Alberta project. Here you see the two -- the two. Cashflows, the blue is the 2005 terms. And then this purplish is the proposed contract. As you can see, under the proposed contract, there is a negative cashflow first, so we are -- end up much worse early in the cashflow, and then we make up gradually over time, but not completely. As you see, we are still a billion short at the end of that day.

So, the inner workings, from a time point of view, of this cashflow is -- is different from the currently -- currently proposed terms.

What this means is that the contract is, as you call it, back-end loaded. Actually, the stranded gas contract has as one of its principles that the Commissioner can negotiate a contract that is more back-end loaded.

Let me just go back to this graph for one second.

What does back-end loaded mean? Back-end loaded means that the State receives less in the beginning and relatively more later on. And that was in the Stranded Gas Act as one of the principles for negotiation. And why was that one of the principles?

Now, obviously, if you move cashflow from the beginning to the end, you make the rate of return of the project better. And, consequently, it is kind of a different form of risk-sharing, and it is moving of revenues that make the rate of return better, that allow the investors to recover faster their investment. And because you allow the investor to recover their investment faster, it is more likely that the project comes about.

So, this table on page 11 is a

demonstration that we are actually having a back-end loaded contract. We share first in the burdens, and we recover it back later on.

This brings us to discounted revenues. The Commissioner talked about undiscounted and discounted revenues. One of the concepts of the Stranded Gas Act, one of the principles, is that we have to look at the discounted revenues. And why do we look at the discounted revenues? That's because of the time value of money. That is because of the fact that money in hand today is worth more than money ten years from now.

So, consequently, we looked at the discounted value for the State. At a 5 percent nominal rate -- actually DNR had a group of -- or have consultants looking at what the appropriate discounted rate for the State would be, because that is not prescribed in the Act. It just says a discount rate. And that was 5 percent nominal, so that would be 3 percent real if you take the 2 percent escalation inflation into account.

If you compare the discounted revenues, obviously, if you have the same revenues undiscounted and now you have this big investment in the beginning, what happens that on a discounted basis, the revenues under the proposed contracts are somewhat less.

Actually, if you compare Alberta versus Alberta, you see that the revenues are about 1.9 billion less on average. If you compare Chicago with Chicago, it is about 1.4 billion less.

So, that means the proposed contract has the same undiscounted revenues, but on a discounted basis, it has slightly lower revenues, 1.9 billion less for the Alberta project, 1.4 billion less for the Chicago project.

Now, why is that? That's, of course, because the State invests. The State has this outlay of initial capital. So, consequently, that are the discounted revenues of the State.

The Stranded Gas Act states that under average and high prices, the discounted revenues to the State should be substantial. Now, as you can see from these columns, under average and high prices, the discounted values are substantial.

Interestingly, the Stranded Gas Act -- Development Act only talks about average and high prices. It was actually contemplated in the Act that under low prices the Government could give up a large amount of Government take to make the project viable.

Actually, that didn't happen, although the Stranded Gas Act contemplates how other nations -- other nations do precisely that. Other nations say, "Oh, in order to solve your net present value problem -- in order to solve your net present value problem, we -- we will give a lot of government take at low prices. We lower the government take at low prices."

This contract doesn't do that. And that is the nice aspect of this participation. This contract does not lower the government take substantially at lower prices.

Canada, the McKenzie Delta project, direct competitor of the Alaska project. Canada did precisely that. Canada said, As long as prices are low, all you pay is corporate income tax and a 1 percent royalty that will go up very slowly to 5 percent over seven years. That's all you pay in Canada if prices are low.

Because Canada decided that in order to get the McKenzie Delta going, the best way was to lower the Government take of the low prices, or under high cost. We're not doing that. We are having substantial revenues under low prices and substantial revenues under average prices and substantial revenues under high prices.

So, quite frankly, the balance that we have in this contract under low prices is very much in favor of the State compared to other jurisdictions or to compare to what the Stranded Gas Development Act had in mind. As I said, this is what the Stranded Gas Act had in mind, that -- we had the option. The Commissioner could have negotiated, say, all the royalties off under low prices or a royalty holiday or a tax holiday or something of that nature to make the project more economic under low prices. That did not happen.

So, as I said, what is remarkable about this contract, or a very important characteristic, is that under low prices the companies have a very poor return, but the State maintains very significant revenues.

And here you actually see some of

the balance with the PPT that we already discussed. Under the stranded gas contract, it is careful on the downside; the PPT is more adventurous on the downside.

Before going into the government take, this has been already a long one-hour discussion, and now we get into the real difficult stuff. So, what I would suggest is why don't we have a ten-minute walk-around, and then we get back to the rest of the government take.

[Break]

COMMISSIONER CORBUS: Could we please take our seats so we can get started?

Thank you.

We're going to get started now. Dr. Van Meurs, will you carry on from where you left off?

DR. VAN MEURS: Okay. A very important aspect of the Stranded Gas Act is that the Commissioner is obligated to evaluate in detail the share of the economic rent that the State receives. And I -- and I'd like to explain this a little bit.

Actually, the -- the law mentions economic rent, but kind of under economists, this is actually known as the divisible income. That is the income that is divided between, say, the investors and the Government.

How is that divisible income determined? Basically, you take all of the gross revenues, subtract all the capital expenditures, subtract all the operating expenditures, and then what is left is your net. What is left is that -- the pie, so to speak, that can be divided between Government and industry.

We have two kinds of government takes. Sometimes I look at what is called the total government take on the project. That means, what all governments take together, Alaska, the U.S. Federal Government, the U.S. lower 48 states, which also has their property taxes and state corporate income taxes, the Canadian Federal Government and the Canadian provinces. So there is what you call a total government take that refers to all of the government take on the project, all the way from Prudhoe Bay to Chicago.

And then I also analyze the Alaska take, and the Alaska take is the take together of the State as well as the affected municipalities.

Here I have an example for the Alberta project at $5.50 per million Btu in millions of dollars. So, here you see the various steps. I got now a wonderful pointer, so -- I still have to learn to operate it.

Oh, there it goes.

Here you see the top number is the gross revenues of the whole project. So, that would be what you sell this for in Alberta.

Then the next line is operating costs, 16 billion you subtract.

The next line is capital costs, 19 billion. And then you get to the very important line that is called divisible income, $199.5 billion. So that's how you calculate that divisible income. You take the gross revenue in Alberta, less the operating costs, less the capital costs, and that gives you your divisible income. And that is 100 percent.

Then you divide that 100 percent in the corporate revenues, the non-Alaska revenues, and Alaska revenues, and the various percentages. So, that is what you see there.

Of the 100 percent of the divisible income, the companies get 49.1 under this scenario, this price scenario for the Alberta project. Non-Alaska revenues, that means all of the other governments other than Alaska, mostly the U.S. Federal Government, but also important, the Canadian Federal Government, receive 28.2 percent, and then Alaska receives 22.7 percent.

And, consequently, that is how we interpreted the Act. So, that is what actually economic rent is defined in the Act as what is called here divisible income, which is more the standard term among the economists.

So, here you see the Alaska take of the project is 22.7 percent. The nonAlaska take is 28.2 percent, and that is for a total of 50.9 percent. And then the corporate take, as it is sometimes called also, is 49.1 percent.

So, that is how the pie is divided.

Let's now look at the total government take for the Alberta project under different price levels. And what you see here is that the total government take under different price levels shows that if the price goes up, the total actually goes down a little bit.

And that is, primarily due to the fact that the overall system is actually slightly regressive, because of property taxes, primarily, and, of course, also because of other features. So, consequently, if you look at the total government take, the overall system is slightly regressive.

What does the word "regressive" mean? The word "regressive" means that the percentage goes down if the price goes up. That means it is regressive with price. And that is what you see here. At 2.50, it is 52.4. At 8.50, it is 50.8. That's less, so we have a regressive system.

Here you see this in graphical format. Here you see the government take in graphical format. As you can see, approximately the take on gas is about 51 percent, but a little bit less if you go for high prices, and a little bit more if you go for the lower prices.

If you look at the Alaska take, what happens? Here you see, under the contract, it is actually slightly progressive. That means the percentage goes up from 21 to the 22.7 that we already looked at, to 22.8. And under the status quo, it actually goes down.

By the time you get to high prices,

very little difference between the status quo and the contract. If you go to low prices, the difference becomes bigger. And why is that?

That is -- is, of course, primarily because of two factors. As you can see, the difference here, 23.6, 22, about 1.5 percent difference here, only 3 percent different. Why is that difference narrowing? Because, precisely how we structured that. As I said, what we're trying to do is target the net present value at the low prices. And, consequently, we are given a slightly better deal at the low prices, but not at the high prices. So, that is what you see happening here in government take terms.

I discussed it in terms of profitability. But now you see this happening actually in government take terms.

And here you see the -- actually, the Alaska take, as you can see, at low prices, the status quo is somewhat higher, about 1.5 percent point more. If you go to high prices, it is about the same. At low prices, we are trying to improve the net present value of the project because that is what is necessary at the low prices. We need to provide some more support for the project.

So, consequently, that is how the government take is being structured.

In fact, this is what the Stranded Gas Act had in mind. The Stranded Gas Act said, actually, the way to make the project profitable and at the same time protect the interest of the State is to make the economic rent or the divisible income progressive. And the reason is very simple. If you make it progressive with price, that means less burden on the down side, more burden on the high side. And as you can see, that is what we're precisely doing. Now, I don't want to oversell this, because this is not what you call strong progressivity. This is very, very modest progressivity, actually, from an international point of view.

But the system is slightly progressive, and that is the result of three factors. One, the upstream cost allowance, which remains constant. It is a constant deduction, so the lower the price, the more important that becomes relatively. The 35 percent GTP credit. And then what is also interesting, and that is an interesting structural aspect, is that the higher the price becomes, the more actually the upstream is worth, because the midstream is a fixed amount. Now, the government take on the midstream is less than on the upstream. So, the higher the price is, the blended average, as -- as is explained in this slide, the blended Alaska take structurally becomes higher as you get higher prices. Because you get more upstream government take and less -- percentagewise, less midstream government take. So, by its very nature, just the structure of the project leads to a slightly progressive system.

For the Chicago project, the situation is the same with the only difference that, as we already discussed, on the total revenues of the project, since now the pipeline revenues, as you can see here -- since now the pipeline revenues are so much more important, the contract actually has a slightly higher government take.

The total government take under the two contracts is regressive, slightly regressive, as you can see here from this graph. So this is a slightly regressive system on a total government take basis.

Now, of course, on a total government take basis, there is not that much Alaska can do, because these other governments have a very important part of that -- that pie.

The Alaska take is progressive interestingly under the status quo and under the contract, and the reason is precisely this upstream effect that I already talked about.

That means, once you go to Chicago, then the midstream becomes much more important. And, consequently, as you see here, this figure is lower than that. That figure is lower than that. So, both under the contract and the status quo, we had already a progressive system.

But, this is structural progressivity, this is not necessarily fiscal progressivity.

Although, with the movement, we tried in the contract to strengthen that movement, as I discussed, because we -- we made the government take on the midstream deliberately less. So, we pushed the progressivity a little bit by taking some out of the midstream and putting that in the upstream.

Here you see the government take,

the scale is only 10 percentage points, so it looks like very progressive, but actually it is -- it is not very progressive from an -- from an international point of view.

On a discounted basis -- remember, we have to look also at the discounted figures. On a discounted basis, the proposed contract is actually progressive either way. For Alberta and Chicago, relatively strongly, actually -- or more strongly, still not very strongly progressive, but somewhat more progressive. And -- and why is that? Of course, on a discounted basis, this investment weighed more. So, consequently, under low prices, that creates a lower burden than under high prices.

So, basically speaking, I would say under the proposed contract, whether you discount it or undiscount it, or whether you go to Alberta, or whether you go to Chicago, you can describe the system as slightly progressive.

Let's now look at cost overruns. As I showed yesterday, I showed the absolute dramatic impact of cost overruns on the project. Let's now look at cost overruns, what it does to the government take, or government revenues.

What you see here is the total Alaska income, again, for the -- for the same scenario, Alberta project at $5.50; and what you see here is that the government revenues, of course, go down somewhat with cost overruns, but not dramatically.

What this shows is that although the investors would be very badly hurt with cost overruns, actually Alaska would not. So, consequently, again, from a risk point of view, the balance is very much in favor of Alaska in this deal.

Doesn't matter whether the prices are low or whether there are strong cost overruns, the Alaska revenues are relatively safe. It's a very important concept of -- of this contract.

Here you see the graph -- sorry, I said 5.50. It's 3.50.

Here you see the graph. This, the government take going down, that's both the case under the status quo and under the contract. And, consequently, basically speaking, we are not disproportionately or significantly proportionately, say, affecting the government revenues if costs go up very significantly.

As you can see from this example and the example that I gave about the price is one of the fundamental concepts of this contract is definitely to provide -- to protect the State quite considerably on the downside. And why is that?

Why is that an essential design? Because, as we could see from all of the graphs of -- of DOR, of the long-term future, oil revenues will continue to go down, very likely. Of course, first there will be the increase with the PPT, but as oil production declines, oil production, oil income will continue to go down.

For the next two generations, we'll have gas income, and it is very important to make sure that those generations can count on that gas income to a certain degree.

So, this is really an insurance policy to make sure that if this gasline comes on stream, we can reasonably assure Alaskans that there will be ongoing income even at low prices, even with big cost overruns.

This is a philosophy that is different from, say, Canada, as I mentioned, for the McKenzie Delta. The Federal Government of Canada said, In case of cost overruns and low prices, you practically pay nothing. That is a truly progressive fiscal system. We didn't opt for that. And we didn't opt for that because for the long duration of this contract, that would be a highly risky position to take.

It's possible that there are cost overruns. It is possible that there are low prices. We cannot gamble too much with those factors. And this is -- therefore, I would describe it as a very conservative contract with respect to the interest of Alaskans. If situations is bad, investors are really in the hole, but Alaska is fine. And that is a very important aspect of this agreement.

Here you see the Alaska take with cost overruns. Again, you see that the take goes down slightly. So the take goes down slightly, but not dramatically, as more international progressive contracts.

So the take goes down slightly, which means that if costs are less, the take goes up. That means with respect -- with respect to cost increases, this contract is also slightly progressive. So we have a contract that is slightly progressive with price and slightly progressive with cost, but on the downside, we are extremely well protected.

What is causing this progressivity risk? Lower cost. Actually that is the PPT credit because, of course, that credit becomes less if costs are lower.

So, the feeder line and the GTP credit play two roles. One, they play an important role in creating some progressivity, and also it creates a very significant increase in the IRR, in the rate of return.

A few words about this GTP and feeder line credit. I realize, of course, that at this point in time the whole PPT is somewhat up in the air, and, consequently, these presentations were prepared on the assumption that the PPT would -- would pass. I didn't have time to change all my presentations in one morning. So -- so, consequently, this was all we could do.

Now, the GTP credit, as you can see here, why do I say it is so important? Just look, for instance, at $3.50. This is no GTP.

This is with the GTP. You just boost the rate of return by half a percentage point, just with that little GTP credit. A very important total feature of the contract. So, with a relatively modest adjustment, but because it is in the beginning of the contract, modest in terms of total outlays with respect to the State, you really help the rate of return problem, which is the Achilles' heel of this project. So that is why that credit was in -- is in that package.

Here, you see the same for the Chicago project. For the Chicago project, this is even more important. Because, as we know, if we have to sell our gas all the way to Chicago, the total revenues of this project are very -- sorry, the total profitability of the project is very difficult.

We also did -- of course, as you know, I work in many countries in the world, and as a result, of course, I also did extensive international comparisons to make sure that the share that Alaska receives is fair.

Now, I compared that with jurisdictions that are in the same situation as Alaska. Of course, if you go to the middle of

Texas or if you go to the middle of Alberta, you find tougher terms for gas, because you're right smack in the market. You're close, you're at the AACO, at the Alberta hub.

As I stated before, the international strong trend is that nations that need to export their gas over long distances either by pipeline, like Canada from the McKenzie Delta, or as LNG, like Qatar or other nations, typically have government takes for gas that are less than for oil.

What I did is I compared a hypothetical 6 tcf gas project around the world, this time based on wellhead values. I didn't take the midstream into account, because the midstream is so different for all of these projects.

Here you see a little bit difficult to interpret graph, but here you -- sorry, table, I first give all the figures. Later on, I'm going to show the graphs. What you see here is the contract. I mentioned already the 51.9 percent -- sorry, this is a slightly higher figure. This is 51.8, because this is just the upstream. The 50.9 that we looked at before included also the midstream.

What you see here is that, of course, under the Alaska Stranded Gas, it is slightly progressive, as you can see here. Now, 1.50 is a wellhead price. That is not a Chicago price now. If you look at Canada, for instance, here you see the enormous difference. Canada would have a much different government take than Alaska. But, then, as the price goes up at the wellhead, so at 5.50 or something in Chicago, or $5, this gets slightly better than Alaska. So they take a much more progressive approach.

Australia, much lower at low prices. Australia, as you know, has the largest condensate -- gas condensate field in the Northwest shelf -- and their market is Asia -- that is actually the kind of fields that competed Alaska out of the Asian market. And they did that precisely with this kind of a system, whereby they have a very low government take at low wellhead prices, only 31 percent, and then it goes up to slightly higher levels, over, say, the mid-50s, at higher levels.

Indonesia does exactly the same thing. Indonesia has production-sharing contracts, but the main feature of gas, and particularly the deeper-water gas fields that are now being developed in the fields, say, in West Irian and so on, that are now being developed, are all being developed under what is considered a very strong tax credit.

And, in fact, what Indonesia is doing, I'm suggesting here, is 35 percent tax credit just on the GTP. Indonesia has much higher tax credits, 100 percent, 150 percent, very strong tax credits in order to protect the gas fields and their very low prices. And that is creating that low government take, say, at a low wellhead price. As you then go up, Indonesia becomes kind of equal to Alaska.

Qatar goes the other way around. Qatar is a somewhat regressive system, and the reason is that in the case of Qatar, actually, there is what you call a feed gas price in the contract. So, actually Qatar is actually capping the field price. Very interesting. The maximum price that the producers get in Qatar is 50 cents per million Btu, and that is all they get. And then over 50 cents per million Btu, it just becomes normal corporate income tax. Below 50 cents, they have to pay additional production sharing. So that is actually a regressive system. And here you see how Qatar is very strongly positioning itself with a low government take -- a low overall government take in terms of taxes. Qatar then makes up for those loss in revenues with a very high level of participation, as high as 70 percent in some of the projects. So, they get their revenues as co-investors.

Trinidad and Tobago is a classical example of a nation that has very different tax regime for oil and for gas. Trinidad and Tobago has been a client of mine for the last 20 years, and so I was intimately involved in the design of the oil terms, as well as the gas terms. And -- and the focus in Trinidad and Tobago is kind of as we -- we're now doing it here in Alaska, that is, try to get good progressivity on oil, but be relatively conservative on gas. And that is what they did. They have a pretty flat system, actually, normal corporate income tax with some surcharges that applies to gas. The royalty they kept very, very low. The whole royalty in Trinidad and Tobago was 2 cents per million Btu. That is the royalty, period, 2 cents per million

Btu. So you can immediately see that they took a very different approach. Now, that approach was very successful. I was very -- I'm always -- was told -- I'm still very proud today that Trinidad was one of the really first LNG projects in -- in the Atlantic area that shipped LNG to both the U.S. and Spain. And they did that with this fiscal system.

Venezuela has huge amount of gas. Right now it is a little bit of a political mess as you know in Venezuela, but interestingly that applies to certain light oil areas, it doesn't necessarily apply to gas.

They have relatively stable conditions on their gas fields and they have also somewhat regressive system. And the reason is that they have a flat 20 percent royalty and then a tax. And that creates a somewhat progressive -- re-- regressive system.

That's what you see here all together in this graph. So, what you see here, this red line is Alaska. As you see, Alaska is slightly progressive system in the upstream. If you add the midstream to it, it becomes even less progressive. Some nations, like Canada, Indonesia, for instance, and Australia, very progressive systems. Very low government take at low prices, and then they make up for it at slightly higher prices. Qatar, actually very regressive system, primarily aimed at, you know, big-volume gas marketing. And, as I said, they make up in their revenues through an overall direct equity participation in the project.

So, that is -- these are actually all the important systems that potentially export gas to -- to the North American market. So these are our competitors. And as you can see, Alaska fits pretty well in the middle of the pack. And, consequently, that is why I think it is -- it is, in conclusion, that from an international perspective, we clearly have a competitive system.

We are less progressive than some other nations have done.

The government of Canada does not depend for 80 percent of -- on oil and gas revenues. Alaska does. So, it is easy -- and the same is true for Australia. It is easy for these nations to take a more adventurous approach to progressivity. And, consequently, that is what Canada has done very successfully. The McKenzie pipeline will most likely go forward ahead of the Alaska line, and that is in no means reason for -- because of the fiscal system they designed.

But that is, of course, to try to mimic something like the Canadian system in Alaska could be absolutely disastrous. And, consequently, that is something that would be very difficult to manage. If I asked you, what are you prepared to give up on the downside, that would be a very difficult question to answer. Would you be willing to give up royalties? Would you be willing to give up taxes? Would you be willing to give up all corporate income taxes if prices are $2 or $3.50, and I think most Alaskans will say, No, no, I don't want to give any of that up. And consequently, because of that -- because of that, I think that is a very good -- that is a very good mentality. But that is a different fiscal philosophy if you are depending for 75 percent, as the Commissioner actually said, on -- on discretionary revenues from oil, then you have to take a more cautious approach than the McKenzie Valley did or Canada did in

McKenzie Valley, Australia, or even Indonesia. Indonesia is an oil exporter, but the percentage of income coming from oil is actually quite minor in the total economy.

So, the conclusion that I like to reach on the revenues is that I think the Alaska revenues and take are highly competitive, provide substantial revenues to the State, as the Commissioner concluded in its findings -- and the affected municipalities, of course -- on a discounted, as well as on undiscounted basis, on any reasonable price scenario, on any reasonable cost scenario, and is protecting, in particular, the State on the downside, which is a very important feature. If we really want to guarantee two generations of Alaskans that are going to depend on these gas revenues more than the oil revenues, that there will be stable income for the state. These terms maximize the benefits to the State.

The Stranded Gas Act, in section 43.82.210(b) requires the Commissioner to establish a balance among six different economic principles. The Stranded Gas Act is actually quite specific as to how the contract needs to be structured. There's a lot of guidance in the Stranded Gas Act, what the Legislature had in mind with the Stranded Gas contract, actually, very remarkably specific. And the fiscal balance, there are six economic principles and two structural principles, and the six economic principles that are established in the Stranded Gas Act are realized in this contract.

The first principle is: Do the terms improve the competitiveness of the project in relation to other development efforts aimed at supplying the same market?

Now, I think we have demonstrated beyond any doubt with the significant increase rate of return, the protection on the downside in net present value and the improvements, particularly in the profitability ratio, that we are improving the competitiveness of the project, significantly.

Two, the terms should accommodate the interests of the State, the affected municipalities, and sponsors under a wide range of economic conditions, potential project structures, and marketing arrangements.

Now, we are not yet marketing the

gas. So, really, the first two issues apply here.

I have discussed with you now the fiscal balance. On the downside, the State really is favored over the investors. If prices are low, if there are high cost overruns, the investors are a deep problem, but the state of Alaska is okay. Under high prices, the investors make very attractive projects that -- very attractive profits that are counterbalanced, counterbalancing this negative downside. So, consequently, there is a reasonable fiscal balance in this contract. The State is protected under a wide range of circumstances. The investors achieve a balance together with the fiscal certainty that either high profits or low -- or high losses are counterbalanced in this contract.

The combined share of the economic rent has to be progressive. Now, we have some progressivity, but it is modest. It is not what you call strong progressivity, and it is for the reasons that I described to you. It is we don't want to gamble too much with the downside on this very important project with the Alaska revenues.

And that automatically means that if you want to balance the project in totality, that you have to leave something in the upside for the investors as well.

Combined share of the economic rent should be back-end loaded. We have a strongly back-end loaded system with the investment -- co-investment of the State of 20 percent, as I demonstrated.

The share of the sponsors should compensate the sponsors for risk under a range of economic circumstances. I think I have explained that abundantly in the morning that even if you look at every one of the seven profitability indicators that we analyzed, that there is a fair balance in compensation among all of the whole range of economic circumstances in terms of price and in terms of cost overruns.

And, finally, the terms should provide the state and the affected municipalities with a significant share of the economic rent when discounted to present value under favorable price and cost conditions. As I have explained to you, we achieve that under favorable price and cost conditions and unfavorable price and cost conditions.

Therefore, I believe that this contract adheres to the six principles established in the Stranded Gas Act. A remarkable guidance from past legislators as to what we needed to do in a stranded gas contract. I think we have adhered to all the six rules that were set out by the Legislature of Alaska in achieving this contract.

Thank you very much.

[Applause]

COMMISSIONER CORBUS: We have over 20 questions to answer. So, why don't you take ten, and we'll come back and get at them.

[Break]

COMMISSIONER CORBUS: We're going to get started now. Just a couple comments on logistics. We will start tomorrow morning at 8:30, not 9:00 o'clock, 8:30, and we will adjourn for the day at 11:30. And then, contrary to what the calender says, we will not start until 1:30 on Monday afternoon, which means it gives you -- you can stay over and fly down on the morning flight Monday morning.

We've had requests for written

copies of the questions and answers, and we will comply with that request. It may take us a day or two. And we will try to keep up with that as we go along.

Like yesterday, there's one or two questions we are going to hold on and answer tomorrow.

We had one question yesterday which was not answered, which I'll take a shot at now, which states that: The Stranded Gas Act requires that the Commissioner conduct an economic analysis determining that the gas is not being marketed due to prevailing costs or price conditions.

Appendix C is not an economic analysis of the Alaska project. It does not show that the cost and price are making Alaska's gas uneconomic. Indeed, Appendix C seems to agree with our consultants that Alaska gas can be produced without economic subsidy. Where is the economic analysis that shows Alaska gas to be stranded as required by the -- by the Act?

Well, I don't know that we quite see our analysis as not being in compliance with the Act. However, we can -- when we prepare our final fiscal interest finding, we will take that into consideration. Perhaps, beef up that section of our report.

Question we have here: The Governor mentioned in his speech that if we don't get a contract on a gasline the Feds might step in and take it over. If the Feds are willing to assume the risk and participate financially, why is this bad for the State of Alaska?

Well, I think this is the kind of question that different people are going to give different answers. My shot would be that the Federal Government take -- take quite a bit longer to get the project on line, and that the private sector would probably be able to build it less expensively. And the lower the cost of the pipeline, the lower the tariffs, and, therefore, the higher revenues to the state.

Next question: Are there any reopener clauses in the -- in the contract, and if so, how do they work?

No, there are not any reopener clauses in the contract. However, the section of the contract on oil certainty is still under negotiation. It's possible there may be such clauses in that section.

Next question: Why would the State of Alaska allow credits on the GTP and feeder line units to improve the producers' IRR instead of the State retaining these credits increasing our level to a higher than 20 percent ownership of the system?

Our ownership of the system approximates our expected ownership in the gas. We expect to own just slightly under 20 percent of the gas, and would own 20 percent of the pipe. We do not believe that it would be possible to increase our ownership to anything significantly greater than our gas ownership.

With that, I'll turn it over to Pedro who's got about 20 questions here.

DR. VAN MEURS: I'm very honored with all of the questions. Very good questions. Excellent questions. It really shows the great interest in -- in this project. And -- and actually, they are very fundamental questions.

The first question is: Please explain how the oil pipeline was built without fiscal certainty.

That actually goes to the heart of

fiscal certainty, a very good question. Many projects around the world go forward without fiscal certainty. In fact, very large projects around the world go forward without fiscal certainty. McKenzie Valley pipeline, our competitor in Canada, is a very good example of that. So, there are large projects in the world, Norway, the North Sea is not subject to fiscal certainty. The large Marnock-Mungo Field, about 10 tcf of gas is along pipeline not subject to fiscal certainty.

So, many projects in the world are undertaken without fiscal certainty.

And whether or not a project is undertaken with or without fiscal certainty really depends on two factors: First, there is the overall political risk factor. So, in a number of countries, there is a high degree of fiscal certainty because companies feel that the government is, say, unreliable politically, or -- or cannot really rely on the political integrity of the government. And, consequently, what happens is that they build in the contract the very significant fiscal certainty provisions.

An example is like -- would be

Angola or Turkmenistan, for instance, which are regimes that are considered, say, unstable -- in many cases corrupt -- and, consequently, the oil industry is extremely careful with signing contracts, and wouldn't want to go in without very extensive fiscal certainty provisions.

There are other projects in the world where the fiscal certainty is not because of political risk, but where the political certainty is the result of the risk balance of the project. Qatar and Alaska are probably good examples of that. Qatar is considered a highly reliable and very industry-friendly government.

Nevertheless, the contracts are subject to significant fiscal stability. And why is that? Because the Qatar LNG projects have about the same risk balance as the Alaska project.

Once the risk balance is such that under downside conditions, under high cost overruns and low prices, there are huge losses on the project, or huge losses in value, not necessarily cashflow losses, but losses in value; then companies really feel that it is only safe to go forward unless there is a fiscal stability arrangement.

And, consequently, because they -- they have to balance the upside against the downside. And that means they have to be certain that the upside is protected if it is realized.

So, that -- that is why you find, in some cases, fiscal certainty provisions, and in other cases not.

The -- and, consequently, whether a project needs fiscal certainty depends on the overall balance. Now, the overall balance is very much impacted by the size of the project and also by the duration of the project.

Alaska, as we now explained at length, has an unusual risk balance with a very long lead time, very -- it could be the worst project or it could be the best project. This is why we have this fiscal certainty on this project.

The oil line was -- was also a large project, but the upside and downside conditions were very different. Oil prices, the net backs, the wellhead prices for oil, particularly in the '70s when prices started to go up, were very much more attractive. As you well know, actually, the project was estimated to be far lower costs than it ultimately happened to be. The cost overrun of the oil pipeline in Alaska is a famous story in itself. It's referenced in -- in fiscal interest finding.

So, consequently, the balance of downside and upside under the oil pipeline and the gas pipeline are two entirely different things, because of the size of the project, because of the losses versus profit balance, and, consequently, the Alaska oil pipeline was not too different from other large projects that occur, say, Europe and North America and some other parts of the world that go forward without fiscal stability.

So, the Alaska project needs fiscal stability because of its uniqueness. That is the real -- the unique, very difficult risk balance that this project represents.

The next question is: Is the basic theory of the gas deal the same as the Governor's oil PPT that is to protect the industry on the low prices and not take any progressivity on high prices?

I always love to answer

philosophical questions. That is a good philosophical question.

The -- when I introduced to the Legislature the oil PPT, I think we explained that the oil PPT by itself, without progressivity feature that the Legislature brought in, was a very progressive tax. So, the -- because at a low prices and high costs, no PPT, zero. At high prices and low cost, the PPT approached more than the original 15 percent for the oil. So, consequently, the PPT, as introduced by the Governor, was a very progressive tax, compared to what Alaska had before. What the Legislature did was to add some other layer of modest progressivity to that particular legislation, and, of course, the Legislature changed the tax rate from the 22 to 21 percent.

So, consequently, the Legislature made the progressive PPT for oil a little bit more progressive.

Actually, that is very much in line -- the whole concept of that is very much in line of what is happening around the world.

Governments feel that on oil you can be quite progressive. Governments like to be progressive on oil and be somewhat adventurous on oil. They're willing to take a lower downside for a higher upside in terms of revenues.

In the case of gas, as we saw from all the graphs that I produced, actually, the government take, as soon as you go over $2.50 at the wellhead, most of the government takes of all our competing gas jurisdictions are pretty well or pretty -- very modest degree of progressivity. In Canada, progressivity is only considered to lower the government take.

So, the philosophy of the gas contract and philosophy of the oil PPT are quite complimentary in a sense that the oil PPT is more progressive, catch the upside in cases if prices are high, but then if prices are low, stimulates the investment with very low tax rate. And then the credits also help, as we discussed so many times in the Legislature, to encourage investment.

The gas deal is very different. The gas deal balances out the oil deal by having much less progressivity, very minor progressivity, as I discussed, but protects future generations of Alaskans on the downside, because we don't know what is going to happen over the next 20, 30, 40 years. And this could be the main revenue source.

And, consequently, the gas deal and the oil PPT, in my mind, are a wonderful balance. They -- they -- they really put Alaskans in a good position to look confidently out to the future with secure gas revenues while if conditions in the world are good, they catch the progressivity on the condensate and the oil. And that, I think, is a very good combination. Many other jurisdictions around the world kind of correct that overall balance. So, I believe, therefore, that the gas contract, as well as the oil PPT, together, form actually a very good balance for the future of the state to maximize the benefits.

The next time -- the next question is: How much time will the 788 million GTP credit be spread out over?

In my model, that is just spread out over the construction period of the GTP. That means while the GTP is constructed, that is in -- I have an eight-year total time, so that is from year 5 to year 8 in my model. In reality, it would be during the construction of the GTP which could be a three-year construction period or a four-year construction period, depending on how this line evolves. And it will -- so the GTP credit will only be disbursed when the capital costs are actually incurred in the facilities. That's the concept.

The next question is: Aren't cost overruns built into the tariff so that the government and producer revenues would not be that important?

Actually, this is a very interesting question, again. The stranded gas contract aligns the interests of the State and the producers so much better than a traditional environment. And why is that?

Actually, since -- if the pipeline tariffs are high, the State revenues are low, and if the pipeline tariffs are low, the State revenues are high. It is really nothing else than moving money from one pocket of the state in another pocket of the state. Or, in other words, by participating in the project -- actually, it doesn't matter what the pipeline tariffs are as far as the State are concerned. Now, this sounds a little bit arbitrary, but, basically, you're just moving money from midstream to upstream. And since the State has its own pipeline tariff on its own gas, and the producers have their own pipeline tariff on their own gas, actually, it doesn't matter to the State and the producers what the pipeline tariff is.

Of course, certain parties have an absolute great interest in getting the lowest possible tariff, and that is why FERC and the National Energy Board, of course, will review the tariff, to make sure that the tariffs are as low as is reasonably possible under the circumstances.

Cost overruns will go in these tariffs depending on the rules of the NEB and FERC. Very high cost overruns may not be passed through. This is precisely some of the details that we will have to work out in the future and that FERC will have to decide about.

So -- but for the overall economics, for the overall economics in my cashflow model, I put all of the cashflows together. So, if you have a cost overrun, that mean cost overrun for the whole project, and as far as the tariff is concerned, that is just moving money from one pocket in the other pocket of the state. So that is why cost overruns are important to the State and to the producers because, of course, they affect the overall profitability of the project.

Does the Canadian government also contemplate offering fiscal certainty?

This goes back to the same question about fiscal certainty. There is no fiscal certainty on the McKenzie line. But then don't forget, either, there is only 35 percent government take if the wellhead value is $1.50 or 2 -- or $2. So, consequently, yes, there is a certain tradeoff between government take and fiscal certainty.

Of course, if you -- if you're willing to have a much more back-end-loaded system, as Canada have, much more progressive system, as Canada has, then the balance of risk is different. And that creates a situation -- because the risk balance is so different, that creates a situation where companies would not need the fiscal certainty on the McKenzie line, and do need the fiscal certainty on the Alaska line. Apart from that, of course, the Alaska line is an order of magnitude, bigger project than the McKenzie Delta line.

What does "undiscounted basis" mean with respect to the slides of the Commissioner?

I think I -- I explained the concept of discounting when I -- when I dealt with net present value. Remember your friend had $1,000 to come in next year, and he wanted to -- to give you -- or he wanted the money to cash out this year? Now, if you're really, really good to your friend, then you give him $1,000 this year for the $1,000 he is going to receive next year. Now, that means no value to the time loss. That is undiscounted. So, that means that you're really not attributing any value to the time.

You take the dollars as they come out as -- as you go forward.

Oil companies and governments often and, very frequently, except for looking at the next cash -- net cashflow, always do things on a discounted basis. So, that is why I presented to you the 3 percent real discounted values for the State income, because that is the basis of the Stranded Gas Act.

The reason that we present undiscounted figures is because it is often much easier to follow. It is an easier way to analyze things then presenting a discounted basis. But if you make the ultimate judgment as to whether this agreement is good for the state or not, it is good to look at the discounted revenues for the state.

You said that the probability of the gasline being built under the status quo is low, and yesterday with even the PPT and the contract there is a probability that it may go forward about 70 percent. What is the probability spread between the status quo and the PPT?

As stranded gas contract? Very high. I -- I believe it is their absolute -- can you absolutely state that the pipeline under no circumstance will ever go forward under status conditions? No, you can't. Because the world is uncertain. All kinds of things could happen that could make this line more attractive than expected today. And that is possible.

Is the probability very low? Yes. I think it is a very low probability that the pipeline would go forward under the stranded gas terms -- sorry, under status quo terms, because, as I mentioned, the rate of return is definitely well below international targets. The net present value and the low prices is well below international targets. And, in particularly, in case of cost overruns, the Chicago project and even the Alberta projects are absolutely dismal projects. And, consequently, that is why it is very unlikely that oil companies would go forward on the basis of the 2005 terms.

How high the percentage is, I wouldn't make a guess. But it is a low percentage. Maybe 5 percent; maybe 2 percent. Something in that area. That is what I would judge about it.

When discussing the rate of return, how comes the obligation to develop factor in the calculation?

This relates to the lease requirements. Companies under Alaska leases have an obligation to develop the -- the fields. If it is economic -- and I'm not an expert on this. There are others that are far more -- have far more expertise about this matter than I do on the -- on the legality and the precise nature of this. Mr. Spencer Hosie has actually addressed committees of the Legislature on precisely this topic.

Under the -- under the leases there is an obligation to develop. The obligation also is based on the fact that in -- in principle, there has to be an economic project.

As you can easily see from my graphs, the judgment as to whether there is an economic project under status quo conditions or even under the stranded gas contract conditions is a very open question. And, consequently, it would not be difficult for oil companies to resist an order to develop the fields in, a ten-year court case. And they may win. So, it is not that easy. The obligation to develop is not just a matter of a notice of the Commissioner of DNR and say, now, today, you have the obligation to develop and go forward, and then they all start working. It is not like that.

The -- this will be a very much disputed provision, and, therefore, the obligation is there, and it is an extremely good obligation. And Mr. Spencer Hosie is very right in claiming that this is a very important obligation to the State, because it would answer, of course, in the considerations of the oil companies.

But whether this project is economical or not is not an easy matter. You could easily see that from my presentations this morning. And, consequently, it would be, if you actually want to go to court and order the companies to develop these fields, this is definitely not the fastest way to get this pipeline built. That could -- the court case -- in Alaska, you have the very unfortunate experience, I think, that under very -- on very important issues, court cases could take a very long time. And, consequently, that is just the way it is. And, consequently, this would be a very difficult court case, and I think, therefore, that insisting on the simple obligation to develop would probably not be the best way to develop this project.

Of course, it is a very important obligation. It is something that is very important to Alaska. It is very important lease obligation, and, of course, it will factor in the judgment of the companies. Of course, it will.

How it will precisely impact on the IRR, I have no idea how they would evaluate this.

In discussing project risk, I used prices of $3.50. And what -- if the gas prices are higher, does this not greatly reduce the risk? Of course it does. Basically, in the fiscal interest finding, we expressed the opinion that our average price forecast is $5.50 per million Btu, and a low forecast is $3.50 per million Btu, and that a high forecast is $8.50 per million Btu. These figures come directly from what is currently the, say, common view of large consulting firms like PFC Energy that continuously look at project evaluations all over the world and are continuously involved in trying to evaluate and rate projects.

So, these high, low, and medium forecast is -- is not necessarily an Alaska forecast. That is kind of how, today, approximately the oil industry believes the price dec is, as the -- as price experts call this. The price dec.

So what I did in the slides is that -- what I was combining in the slides was the probability of a low price with cost overruns, because that is really the risk. Of course, if prices are 5.50 and there are cost overruns, then the project may well stay reasonably profitable. So, consequently, the -- the degree to which cost overruns can be absorbed depends very much on price. High prices, yes, there could be cost overruns; low prices, now you're dead. So, consequently, all I was trying to do in my presentation was not implying that the average forecast is necessarily $3.50. I'm just was trying to display the possible high-risk combination of low prices and cost overruns.

I fully agree that if there are cost overruns under higher level of price, that the effects are not at all that serious as I portrayed in my presentation. Of course not.

If the legislation -- sorry, if the Legislature signs off on the PPT and amendments to the Stranded Gas Act and the contract proposal and then the 30 percent chance that no construction happens, what recourse would we have?

The work obligations under the contract specifically state that if the producers do not go forward with due diligence under this contract in constructing the line prior to project sanction, which is the moment that -- after the certificate has been granted and the FERC has special -- specified the construction schedule that they have to adhere to, after that moment, if companies do not proceed diligently with the project before that moment, the contract is terminated. You could -- subject to arbitration, of course. There could be reasonable reasons for some project delays that are prudent, and the State would have to then prove that there was not this prudency test.

But if companies don't go forward with this project after they have signed in a diligent matter, then this contract can be terminated. Now, if the contract is terminated then, of course, the fiscal stability that we just talked about falls by the wayside. So, if the contract is terminated, then it is up to the Legislature to decide. So, if this contract is terminated, you have the hammer. It is very simple. You decide what happens afterwards.

So, consequently, the penalty for not proceeding is very significant. And, consequently, that is why the work obligations under the contract, we will come back on that in -- in the coming days, but, as you can see from the fiscal interest finding, I did an extensive review of similar work requirements on large projects around the world, and the work requirements under the Alaska contract are the best in the world. So, we have very strong work requirements. And the reason for that is -- at least comparatively speaking. And the reason for that is that there was no doubt in our minds that it was the desire of the Alaska public that there would be a strong work requirement, that once this deal is signed, that, indeed, no stone will be left unturned to get this pipeline going.

Nobody knows what the future is. If on project sanction date interest rates are 10 percent or 12 percent and cost overruns appear to be going to the 100 percent and the price is $2.50, this project cannot go forward. So, there is always this possibility that it will not go forward.

But absent that, there is a strong work obligation. If they don't go forward diligently, this contract will be terminated, subject to arbitration. There is no other large project in the world that has such a clause in it. So, this is a very strong provision.

If no progressivity is built in and Henry goes to -- that's the Henry Hub price, supposedly, goes to $15 in 2006 dollars, will we have another broken ELF? Given the run-up in price since we've been at the table, shouldn't the Legislature add progressivity to the contract, which will work well over time?

As you all know, I love progressivity. So I am definitely an economist that loves progressivity, and I always fight for progressivity, and that is why I am so happy that the Governor accepted my proposal for the PPT tax, because that was -- as I stated, it was already a very good progressive tax.

As I also, I think, have explained hopefully today, is that we look at the stranded gas contract differently than the oil PPT. And the reason is the timeline. The reason is the future of Alaska. The reason is the competitiveness of this project on an international basis. And the reason is also that progressivity in this contract doesn't mean exactly the same thing as what it meant under the oil contract.

To go for a Canadian or an Australian-style system, it clearly is very stimulative for large-scale developments. This very low government takes at low prices is not something that I can honestly recommend to the Legislature for the reasons that I explained. We don't know what is going to happen over the next 20, 30 years.

We have -- if this gas will flow for two generations of Alaskans, if -- if we go for this system, we have to be reasonably sure that if this pipeline comes on stream, that it means significant revenues for generations to come and that it is not a gambling casino whereby under low prices we get nothing and under high prices we get very much progressivity. So, the problem is the economic structure under the stranded gas contract is different from economic structure under the PPT, and that is a very important concept. We are far more conservative in this contract than under the PPT.

Could there come a time that you would say that, yes, there are very high gas prices, in fact, gas prices were $13 per billion Btu since last October. So, consequently, yes, there could be very high gas prices.

Under very high gas prices, the revenues, of course, to the State will be absolutely astounding, but the profits to the companies will also be astounding. Now, this is, as I showed on my charts, even at $8.50, the revenues are very high. The profits are very high. But, at low prices, it is a disaster. While Alaska is safe. And that's a different balance. So, that's what we have to consider.

How safe do we want to be on the downside to achieve, say, a viable project? What is the balance. If we want to be safe on the downside, then you cannot be progressive. This project is not economic enough to have it both ways.

So, consequently, this is -- this is, say, something that is very important to consider. And that is part of the design of this contract, contrary to priority design of the oil PPT.

Using the PVN model what is the impact on MPV for one-year delay, two-year delay, or a move from 10 percent to 12 percent capital, impact of rising discount rates?

Delays do not necessarily impact very much on the rate of return because if there is say, one -- depending on when the delays occur. If the delays occur in the next few years, the stream of capital investment remains essentially the same. Say, the pattern of capital investment. So, interestingly, the -- the -- the delays do not necessarily impact the eventual rate of return on the project.

They have a significant impact on a net present value calculated in 2006 dollars. If you calculate a net present value in 2006 dollars, then every year that you delay this cashflow is almost a 10 percent loss.

So, delays in the project, there's a 10 percent discount rate impact the net present values to the companies and to the State very significantly. So, from that point of view, provided you analyze the project in 2006 dollars.

If you go to discount rate of 12 percent, and, yes, some oil companies use 12 percent, then, of course, the total net present value will go down. But those companies would also evaluate all the other projects at a higher discount rate because they use a higher discount rate because their cost of capital would be higher. And, consequently, companies with a high discount rate are not the right companies to build this project. So, there are the companies with the lower discount rates like, say, the major oil companies that we're working with that are the natural investors for a project of this nature.

Why do we go to RIK inside of RIF if we assume that we lose 2 percent? And then why wouldn't we have the oil companies taking the best -- do their best job of marketing of all the gas, and we just get the advantage?

Good question, again. Good point. Why are we doing that? Under the current royal -- under the current leases, we have this very significant benefit of being able to switch between royalty in kind and royalty in value, and to pick the higher of the -- of the prices that are being considered for royalty valuation. So, you would give that up if you go to this concept of State risk-sharing and participation.

The reason that we give this 2

percent off is precisely because the rate of return of this project needs to be improved, and the only way to do that is to actually participate along the lines that I explained.

If you want to reach the same rate of return with -- by not participating, then you have to have a much lower government take. You have to give up far more than that 2 percent. So, consequently, the idea of giving the 2 percent up -- the 2 percent, of course, is in the status quo calculation. The idea of giving the 2 percent up is -- is entirely because that is inherent to the State taking its gas in kind and using that as the main mechanism to improve the rate of return of the project.

The State, between 2009 and 2015, loses billions compared to the current law. By what year would we have made up all of those losses under the contract?

I can give you that answer very accurately because that, of course, is what you have economic models for, but I don't know that by heart, I have to run the model. And it depends, of course, on the -- on the price levels that you assume. The higher the price, the faster the State will recover the investment. I can say that it will be relatively quick if you realize that the State, assuming a 20 billion project, the State will invest 4 billion and under average scenarios, you may have 50 or 60 billion dollar of revenues so you can -- over 30 years. So you can easily see that it will be relatively fast, but I would have to look at my model to give you the exact answer. So what I will do is I will run those cases and see when payout occurs, and when I'm back here in a future presentation, I will give the answer -- more exact answer to that question.

Why do companies use 10 percent discount rate while the -- the State uses 3 percent?

A very important question, again. The difference is -- and, actually, there's always immense discussion about discount rates to be used. The reason that companies, typically, use 10 percent is that the cost of capital structure of companies and the cost of capital structure of governments is rather different. And, consequently, it actually depends on your cost of capital, what -- what the discount rate is.

The consultants actually which work for DNR and determine the various rates, of course, looked at the cost of capital for the State largely on a municipal bond rate basis, which is very different than if your cost of capital relates to investors that like to see the high rate of return on their investment, and you have, say, only a very small share of that financing, and you have a risk component, say, on a worldwide investment basis.

So, consequently, the discount rates were recommended by -- were actually not my discount rates. They were recommended by DNR consultant in order to make sure that we all used the same assumptions in the various models.

Could you use different discount rates? Yes, you could. We could evaluate the State discount rate on a higher number. You could just as well say, Okay, we throw some risk premium in for the State as well, although State revenues are largely just one-line revenues and, consequently, are not as risky as -- as oil company investment.

These rates are widely debated. So, there is no particular dogma why you need to use rates of one particular rate rather than another.

As I demonstrated, since the State is actually making a significant upfront investment, the higher discount rate you use, the -- the less, of course, the revenues become, relatively rapidly.

So, consequently, the discount rate is important and it is, again, no difficulty, and I'm sure that over the coming weeks and months, we will probably do runs at other discount rates if -- if that is so required.

In fact, in the PVM model, we crank every discount rate out between zero and 10 percent. So you can look at whatever discount rate you'd like.

Is the GTP boost to the IRR a product of the lower producer cost for startup and the time value of money? Did you figure on the credit flowing through to a lower -- lower tariff?

No. In the model I actually spent a lot of time with our FERC experts like Mr. Bob Loeffler and so on, because I wanted to know how would FERC react to a GTP credit. And the response that came back was that actually FERC would not take this into account in normal rate base, say, considerations.

So, consequently, in my model I didn't either. Of course, as I just mentioned before, as far as the state share and the producer share -- this is nothing to do with third parties, but just between the State and the producers. It actually doesn't matter what the tariffs are, because we get our own net back for our own tariffs, and the producers get their own net back for their tariffs.

So we have actually -- it is like two separate businesses. And, consequently, you are not necessarily improving the State revenues with lower tariffs. You are improving the revenues of certain parties with lower tariffs, and that is why the State has had a traditional interest in stimulating exploration, and, of course, arguing in front of FERC for the best possible tariffs.

The State under this contract doesn't lose that power. So, there is nothing in this contract that prevents the State from representing the State's interest in front of the regulatory agencies. And, consequently, the State will continue to fight, as they have traditionally done, for the lowest possible tariffs for Alaska consumers and for Alaska explorers.

At high oil prices, you say Alaska revenues are protected. However, it is not good for the system to have higher tariffs. That would discourage independence that we want to incentivize.

I absolutely agree, and that is what I just mentioned. There is nothing in this agreement that prevents the State of Alaska to fight for the lowest possible tariffs and FERC.

Question, fiscal certainty on oil is necessary for oil industry. Legislatures do not like it. If the contract does not contain fiscal certainty on oil, is the gas contract still viable?

This goes back to the overall risk balance that I mentioned before. The companies have insisted absolutely on fiscal stability for oil. Because of the unusual risk balance in this contract and because of the fact that there is enormous potential in the Alaska North Slope to transfer government revenues or government -- government take from oil to gas and vice versa. So, not having fiscal stability on oil would be an immense risk factor to the companies, an immense additional risk factor to the companies. And particularly, it would also affect investments in any gas fields that has condensates associated with it, because there would be no fiscal stability on the condensate. We consider the condensates as liquid and as oil under the legislation.

So fiscal stability on oil is a very important issue. That is why it is included in the contract. And is it possible to think of other combinations and permutations? Of course, it is possible. But now you are thinking about rather different structures. And in those structures you cannot maximize the revenues to the State to the degree as we did under this contract. So, as I stated, in Canada McKenzie Valley goes forward without any fiscal stability. Can you do that? Yes, if you're willing to accept, say, 30 percent total government take if wellhead prices are low and if you have certain other kind of characteristics for the project.

So, I think on balance it would be prudent to say that it is highly unlikely that the project would go forward without fiscal stability on oil based on the terms and conditions that are there. You could think of a contract that is structured very differently. I don't think in the interest of the State, if you -- if you would have a different profile. Therefore, I think the combination of fiscal stability for oil and the highest possible revenues under low-price conditions and low and high cost overruns are a good combination.

What is -- of the 60 largest projects in the world, what was the medium cost overruns, Kashagan cost overruns, for instance, what was the cost overrun on the Alaska pipeline?

Actually, I'd like to clarify that the 60 projects that we compared with are 60 projects that are now on the drawing board, so we don't know what the cost overruns are. So, these are the kind of projects that oil companies actually sit in their boardroom looking at, comparing it with Alaska. That is what we wanted to do. Projects that have already been built are not relevant, because that is some cost.

So, we selected out of the PFC energy database all the projects that are still about to go, that are right now under consideration, where investment decisions are right now being made. So, we don't know what the cost overruns will be on that project.

Kashagan has just started, and, consequently, we don't know what the cost overruns on that project will be. So, consequently -- and that is why if there are cost overruns in Alaska, there may be similar cost overruns on other projects. For instance, if steel prices go up, cost -- you know, you will have similar cost overruns on all of the projects. What worries me very much is that, of course, with the very high capital cost of the Alaska project, it is likely that cost -- worldwide cost overrun conditions will affect Alaska more than other projects.

Please discuss -- oh. Oh, this is a good one. Could the Alaska -- all-Alaska gas pipeline be a nibbler project. That is interesting.

I expressed -- I expressed the opinion that, of course, all these projects --

smaller projects, more profitable projects come in to nibble our gas -- Alaska gasline project to death. So this is one Alaska project nibbling the other to death. That is a very interesting concept. But, no, let me explain the situation that -- of course, in the coming days, a detailed comparison will be made with alternative projects in Alaska. That was part of the duty of the Commissioner to evaluate this project. We wanted to make sure that this project was the best opportunity to go forward with gas in Alaska.

Now, the reason that this stranded gas contract is in front of you and a fiscal interest finding has been expressed is that we firmly believe that this project is the best project.

There is an enormous bottleneck that is sometimes not properly understood with respect to alternative projects. For alternative projects to proceed, oil companies would have to sell their gas to somebody that is involved in that project, or, conversely, would have to commit to the shipping arrangements on such other projects. And oil companies would only sell their gas if they truly believe that that's the best price they can -- the best value they can get for the resource.

If you own a house and you put it on the market, you go to your real estate agent, and you try to get the best possible price. Oil and gas economics is property economics. The oil companies have a property that is the exclusive right to produce that gas, and they like to maximize their benefits from that gas. Just as you would like to get the best possible price for your home if you sell that home.

And a basic concept of our whole society is property right. And a basic concept is that if you sell your home, you have the absolute right to sell it for the best possible price. State cannot come in and say, You have to give a discount on the sale of your home because that's in the interest of the State, but that doesn't work like that.

So, that is why it is very difficult to insist that oil companies would sell their gas for a lower price or make shipping commitments that are more costly than they believe are necessary to bring their gas to market. And, consequently, that is, of course, a major stumbling block in any other project.

On top of that, there is another important stumbling block. Let's suppose, let's suppose that, indeed, an alternative project would result in a better price and would result in a better shipping -- more attractive shipping commitment. Companies would still want fiscal stability. Or, in other words, under another alternative project, you still need a stranded gas contract.

So, consequently, that is an enormous misunderstanding. People think that we have alternative projects that you just pick that project and this project and under this project you have fiscal stability. No, it is not like that. Fiscal stability and a fiscal contract is step one to any project. Without a fiscal contract, without fiscal stability, companies would have absolutely no interest to make any gas sale agreement. Why? Because how can they even evaluate the economics if they don't know the fiscal terms are.

So, consequently, a fiscal stability contract is step one no matter what project you look at. And, consequently, that is sometimes not understood. People look at it as if it's a totally different project. Any project requires a fiscal stability contract, point one. And if the companies are interested in our project, then you would have to sell the gas or the companies would be -- have to be interested in making the shipping commitments, and they have to be internally convinced that this is the best project and the best value for them for what they consider their property.

So, that is why the Alaska -- all-Alaska project by definition cannot be a nibbler project.

Please discuss the probabilities and confidence level of gas prices over an expected range, and how does the 3.5 million Btu, I think, compare to higher or lower expected value?

No. As I mentioned in our fiscal interest finding, we have given an average price of 5.50, a low price of $3.50, and a high price of 8.50. We are not attributing probabilities to this. Because that is a very difficult thing to do, to attribute probabilities to this.

As I indicated, it is -- North

American market is an extremely volatile market to try to predict gas prices for the next 40 years, even the next week is a very difficult exercise. So, consequently, we are not attaching probabilities.

Nevertheless, at least in the report -- nevertheless, DNR built a very sophisticated model, a very -- very good and very interesting model that does all kinds of probability work and that results in probability forecast. Their model, indeed, indicates that the 5.50 is the most likely one, and that 3.50 is an unlikely price. But how unlikely or how likely that is depends so much on the inputs in the model. So there is a whole ream of inputs, more than 100 different assumptions that you have to make, before you get to the probability of the price, and it all depends, then, on what you assume.

For instance, what do you assume about the likelihood of landed prices for LNG and the volumes of possible LNG? So the model is a very sophisticated model. It has been very useful for our analysis. It was built with the support of the Legislature, in the budget last year, and it is a very useful model to try to understand the volatility and -- and the probablistic effects on the market. But, as I said, you have to make so many assumptions to come up with a probability distribution that we felt it was better not to express probabilities because the market is just too volatile. And, therefore, we have to make sure that this agreement is good under every price, so that we have a good deal under every price. That's the --

COMMISSIONER CORBUS: But, nevertheless, DNR is going to be here tomorrow, and we're going to give them a heads up to go back and look at that report. They may have some comments on that.

DR. VAN MEURS: On this, yes.

It says the models you analyzed -- this is the last question. The models you analyzed don't mention the Econ One analysis done for the Legislature with no financial -- showing that there's no financial condition. The gas project is quite profitable.

To begin with, Econ One, I provided the PVM model to Econ One. And, actually, Econ

One used the PVM model to make the presentation to the Legislature. So, consequently, there was no such thing as an independent Econ One model. I think in the meantime, they may have built one. But when they made the presentation to the Legislature, it was actually based on some slight adjustments to -- to my model. So, consequently that is the presentation that was provided.

Econ One did something that was interesting. What they did is they looked at what would happen if you would actually sell the gas in the Arctic directly at the wellhead, so to speak, directly at the point of production.

That -- now, you don't have to make this whole investment.

So, if actually you could find a buyer that is willing to -- or several buyers, that are willing to make very large shipping commitments and they absorb the project risk, they underpin -- the buyers underpin the construction of the line. The buyers provide the shipping commitments. The buyers sign the piece of paper that say, We shall pay over the next 20 years $1.50 or $2 per mcf or a million Btu to transport that gas.

If the buyer signs that piece of paper, then, of course, this is a very profitable project. Because now the producers, all they have to do, is sell gas at the wellhead. They don't have to invest anything. They don't have to make any investment. So, consequently, if you look at this project on the basic assumption that a buyer or buyers would take the full risk of this project, so all the risk is transferred to the buyers, then this could be a very profitable project, because there's no investment associated with it from a rate of return point of view.

Actually, the total net present value of the gas actually doesn't change very much, because that is related to the overall value of the gas, nor does the cashflow change very much. But from a rate of return, of course, if you don't invest anything, then you have this high -- high rate of return. So that is where these high figures came from. They used my model. I had no quarrel with the result they presented. When they presented their result, I said, yes, I -- I subscribe -- I have no disagreement with their -- with their analysis.

That is the answer to all of the

questions.

COMMISSIONER CORBUS: Okay. We had two other questions that we're not going to answer today. One of them concerns the reserves tax, and the other one concerns penalties that could possibly be applied to the producers if they do not diligently pursue the project before project sanction, or after they have started construction.

We are, again, scheduled to meet tomorrow morning at 8:30.

The topics are comparison of alternative for getting gas to market and key Alaska issues, Alaska hire, in-state use of gas, and fiscal certainty for explorers.

So we'll see you at 8:30.

Thank you.

[Legislature adjourned at 5:01 p.m.]

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